United States Agency for International Development

SOUTHEAST EUROPE REGIONAL WORKSHOP ON

DEVELOPING UNBUNDLED TRANSMISSION TARIFFS

United States Agency for International Development
Ministry of Economy of Croatia
Hrvatska Elektroprivreda
United States Energy Association

In Association with
Pierce Atwood

Zagreb, Croatia
May 27-29, 2003

Ministry of Economic Affairs

USEA United States Energy Association

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SOUTHEAST EUROPE REGIONAL WORKSHOP
ON THE UNBUNDLING OF TRANSMISSION TARIFFS

Zagreb, Croatia
May 27-30, 2003

Sponsored by:
United States Agency for International Development
United States Energy Association

Table of Contents

Agenda	1
Presentations **Wednesday, May 27 - Morning**	
Unbundling Accounts and Separation of Assets: A Preparatory Step to Unbundled Tariffs *Jan Karlak, Utilities Specialist, Public Utilities Commission of Ohio* *Max Chau, Manager Transmission Planning East Region, American Electric Power*	2
Athens Memorandum: Provisions and Requirements for Unbundled Accounts and Unbundled Transmission Tariffs *John Gulliver, Pierce Atwood* *William Polen, Manager for Europe & Eurasia, United States Energy Association*	3
Country Status Reports on Development of Unbundled Transmission Tariffs	
Albania *Kastriot Sulka, Head of Tariff/Price Department, Electricity Regulatory Authority of Albania*	4
Croatia *Mico Klepo, Chairman, Croatian Energy Regulatory Council*	5
Kosovo *Rashid Krasniqi, Manager of Maintenance Department of Transmission Division of KEK*	6
Macedonia *Dr. Vesna Borozan, Assistant Professor, Department of Power Systems, St. Cyril & St. Methodius University*	7
Romania *Florin Gugu, Director, Tariffs a& Economic Department, National Electricity & Heat Regulatory Authority*	8

Montenegro *Dragan Bojovic, Deputy Minister of Economy of Montenegro, Serbia & Montenegro*	9
Wednesday, May 27 - Afternoon Presentations	
Transmission Pricing – Principles and Practical Experiences *Konstantin Petrov, Senior Consultant, KEMA Consulting*	10
Western European Case Study *Manuel Velasco, Senior Adviser of the Regulation and Studies Department, Red Electrica de Espana*	11
South East Europe Case Study *Majda Paripovic, Head of Economy Department, Energy Agency of the Republic of Slovenia* *Bojan Kuzmic, Counselor to the Director, Technical Department, Energy Agency of the Republic of Slovenia*	12
Thursday, May 27 Detailed Case Study of Croatia's Unbundled Tariff	
Essential Conditions for a Network Tariff *Charlie Zimmermann, Nexant*	13
Designing and Calculating a High Voltage Network Tariff *Charlie Zimmermann, Nexant*	14
Background Material	
Transmission Network Fees for Croatia *Charlie Zimmermann, Nexant*	15

1

SOUTHEAST EUROPE REGIONAL WORKSHOP ON DEVELOPING UNBUNDLED TRANSMISSION TARIFFS

May 27-29, 2003
Zagreb Croatia

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Hrvatska Elektroprivreda
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In Association with
Pierce Atwood

May 27, 2003

8:00 pm **Opening Reception**
Restaurant "Hrvatski kulturni klub"
Trg maršala Tita 10
Zagreb, Croatia
Tel: +385 (0)1 48 28 084

May 28, 2003

9:00 am **Welcoming Remarks and Overview of Workshop**

William Jeffers, United States Agency for International Development Mission Director to Croatia

Dr. Goran Granic, Deputy Prime Minister of the Republic of Croatia (to be confirmed)

Roman Nota, Assistant Minister for Energy, Ministry of Economy (to be confirmed)

Ivo Covic, President of the Managing Board for Transmission, Hrvatska Elektroprivreda (to be confirmed)

Jamshid Heidarian, Senior Energy Advisor, Office of Energy and Environment, Bureau for Europe and Eurasia, United States Agency for International Development

Overview of the Croatian Transmission System
Ivica Toljan, Member of the Managing Board for Transmission, Hrvatska Elektroprivreda

Overview of the Workshop
William Polen, Manager for Europe & Eurasia, United States Energy Association

9:45 am **Athens Memorandum: Provisions and Requirements for Unbundled Accounts and Unbundled Transmission Tariffs**
John Gulliver, Pierce Atwood/William Polen, Manager for Europe & Eurasia, United States Energy Association

10:15 am **Unbundling Accounts and Separation of Assets: A Preparatory Step to Unbundled Tariffs**
Jan Karlak, Utilities Specialist, Public Utilities Commission of Ohio
Max Chau, Manager Transmission Planning East Region, American Electric Power

- Definition of Unbundling
- Distinguishing Between T&D Assets –7 Factor Test
- Regulatory Proceedings During the Unbundling Process
  - Interaction Between Regulator and Regulated Utility
- Use of Uniform System of Accounts in the Unbundling Process
- Overview of American Electric Power
- Process Used to Unbundle Assets

11:15 am **Morning Break**

11:30 am **Status Reports on Development of Unbundled Transmission Tariffs**

Kastriot Sulka, Head of Tariff/Price Department, Electricity Regulatory Authority of Albania,
Jane Wilson, Pierce Atwood, Bosnia and Herzegovina,
Svetla Todorova, Commissioner, State Energy Regulatory Commission of Bulgaria,
Mico Klepo, Chairman, Croatian Energy Regulatory Council,
Rashid Krasniqi, Manager of Maintenance Department of Transmission Division of KEK, Kosovo,
Dr. Vesna Borozan, Assistant Professor, Department of Power Systems, St. Cyril & St. Methodius University, Macedonia,
Florin Gugu, Director, Tariffs a& Economic Department, National Electricity & Heat Regulatory Authority of Romania
Dragan Bojovic, Deputy Minister of Economy of Montenegro, Serbia & Montenegro
Dr. Gligo Vukovic, Advisor, Ministry of Mining & Energy of Serbia, Serbia & Montenegro

1:00 pm **Lunch**

2:30 pm **Transmission Pricing – Principles and Practical Experiences**
Konstantin Petrov, Senior Consultant, KEMA Consulting

- Nature of Transmission Network
  - Regulated and Competitive Assets
  - Essential Facilities
- Objectives and Methods
  - Pricing Objectives
  - Methods
  - Major Cost Components
- Network Connections
- Average and Marginal Cost Pricing
- Major Steps in Transmission Pricing
- International Experience

3:45 pm **Afternoon Break**

Unbundling Transmission Tariffs: European Case Studies in Process and Methodology

4:00 pm **Western European Case Study**
Manuel Velasco, Senior Adviser of the Regulation and Studies Department, Red Electrica de Espana

- Developing Revenue Requirement
- Reporting to the Regulatory Authority

4:45 pm **South East Europe Case Study**
Majda Paripovic, Head of Economy Department, Energy Agency of the Republic of Slovenia
Bojan Kuzmic, Counselor to the Director, Technical Department, Energy Agency of the Republic of Slovenia

- Examining & Liberalized Market in Slovenia
- Process of Price Regulation in the First Regulatory Period
  - Consultation Paper
  - Company Data According to Unbundled Activities
  - Evaluation of Costs
  - Required Investment
  - Revenue Requirements
  - Smoothed Revenue
  - Determination of "X" Factor
- Methods Applied for Determination of Network Charge
  - Cost Allocation to Customer Groups
- Ancillary Services

- Cross Border Trade

5:30 pm **Summary of Day One and Overview of Day Two**

8:00 pm **Dinner**
Kaptolska Klet Restaurant
Kaptol 5
Opposite to the Cathedral
Tel: +385/01/4814330

May 29, 2003

Detailed Case Study of Croatia's Unbundled Transmission Tariff

9:00 am **An Examination of the Croatian Transmission Tariff Model**
Charlie Zimmermann, Nexant

Essential conditions for a network tariff

- Apply HV network tariff to all transactions requiring use of HV network
- Metering of power flows is required
- Transmission Operator accounts must include both revenue and expense line items associated with inter-TSO payments.
- Other Transmission Operator revenues must be reflected in the HV network tariff calculation
- Transmission Operator financial accounts must include both revenue line items and expense line items associated with transit flows other than inter-TSO payments
- The Transmission Operator must operate as a profit center and prepare an income statement, balance sheet, and statement of sources and uses of funds
- Pro forma financial statements may be used to develop a HV network tariff calculation.
- A Transmission Operator must maintain strict limits on accounts receivable and accounts payable
- The HV network tariff should not be used as a "social tax" to provide cross-subsidies

10:30 am Morning Break

10:45 am Designing and Calculating a High Voltage Network Tariff

- Definition of customer classes, by voltage level
- Identification of services to be provided, and standards of service quality
- Method of valuation of electric energy losses in the HV network
- Forecast of investments needed to meet standards of service quality
- Setting of financial objectives; definition of financial "health" and selection of a method for valuation of assets

- Selection of a 12-month period in which the tariff will be in effect and will meet the financial objectives
- Preparation of financial accounts for at least one fiscal year
- Forecast of the annual revenue required for the TO to meet its financial objectives
- Design of the tariff: capacity charges, energy charges, and costs of reactive power control
- Calculation of the proposed tariff
- Calculation of tariffs during a transitional period, if a transition is necessary

12:45 pm Lunch

2:15 pm **Applying the Tariff Model: the Process to Develop the Transmission Tariff Methodology and Transmission Fees**
Miroslav Mesic, Managing Director, HEP Transmission

3:30 pm **Afternoon Break**

3:45 pm **Interactive Simulation and Tariff Development Exercise Using the Croatian Tariff Model**

5:15 pm **Conclusions and Adjourn**

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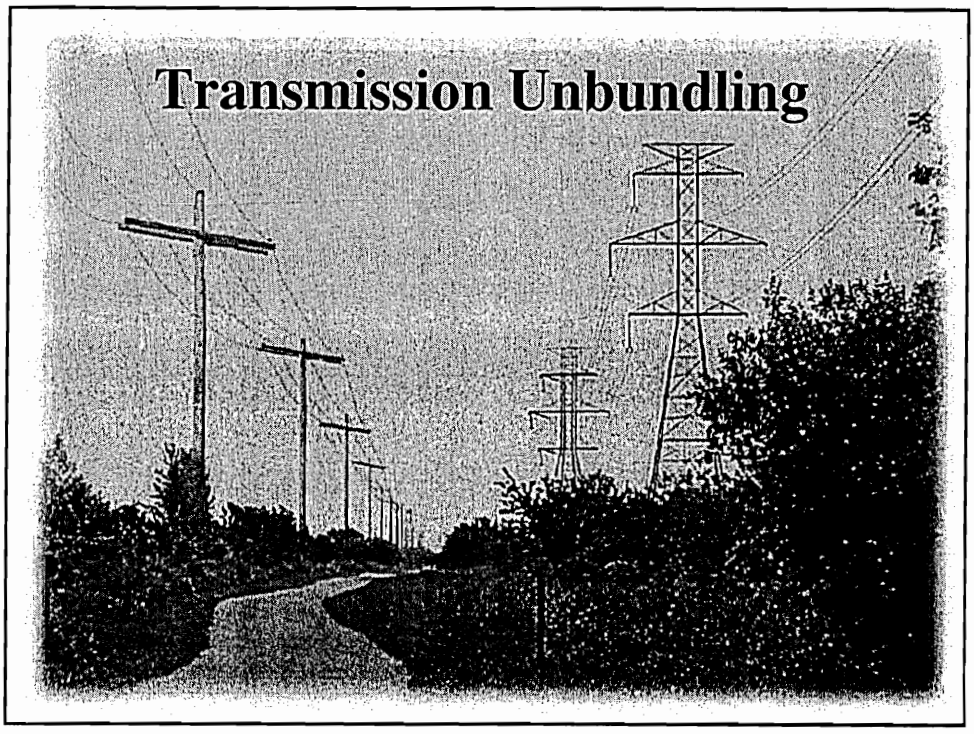


Transmission Unbundling:

"An Example of How This Was Done in the United States of America"

From the Regulator's Perspective:

Ms. Janice Karlak

Public Utilities Commission of Ohio, U.S.A.

From the Electric Utility Company's Perspective:

Max Chau

American Electric Power, U.S.A

Southeast Europe Regional Workshop on Developing Unbundled Transmission Tariffs

May 28, 2003

Zagreb, Croatia

From the Regulators' Perspective:

- **"Unbundling"-- the separation of both the physical and the financial elements of electricity service, began in the U.S.A in the early 1990's with passage by the U.S. Congress of the Energy Policy Act of 1992.**

From the Regulator's Perspective:

This was followed in 1996 by Order No. 888, issued by the Federal Energy Regulatory Commission ("FERC"), to further deregulate the wholesale generation market.

- **Order 888 also asked the States that deregulated electricity in their local retail markets and unbundled their electric service rates to identify-- in consultation with jurisdictional electric utility companies, the differences between the high voltage transmission system and the local distribution wires facilities, using a "7-factor test" contained in the Order.**

From the Regulator's Perspective:

The FERC 7-factor test includes the following:

1) **Local distribution facilities are normally in close proximity to retail customers;**
2) **Local distribution facilities are primarily radial in character;**
3) **Power flows into local distribution systems; it rarely, if ever flows out;**
4) **When power enters a distribution system, it is not recognized or transported to some other market;**
5) **Power entering a local distribution system is consumed in a comparatively restricted geographical area;**
6) **Meters are based at the transmission/local distribution interface to measures flows in the local distribution system;**
7) **Local distribution systems will be reduced voltage.**

From the Regulator's Perspective:

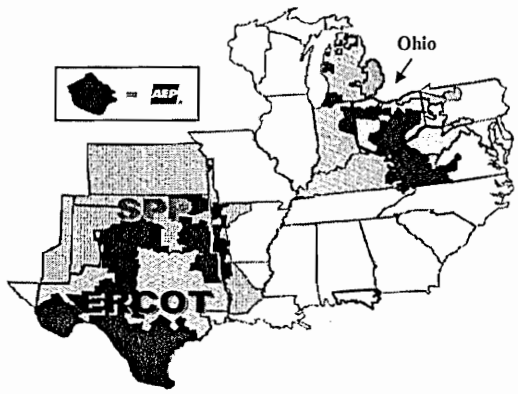
The Public Utilities Commission of Ohio ("PUCO") opened a case in December 2000 asking the electric utility companies in our State, including AEP, to file summaries of their proposed unbundling plans with our Commission.

- **AEP replied that as a first step, it would make an informal presentation to the PUCO of its general technical unbundling plan, but also wanted to gain a consensus of all the States having jurisdiction over the AEP system.**
- **The Ohio Commission agreed, stating that the informal discussions would constitute neither an acceptance nor a rejection of AEP's transmission unbundling plan.**
- **In addition, under Ohio's new electric retail competition law, utility company generation was no longer under the jurisdiction of the Ohio Commission—further adding to the complexity of the job of "unbundling" for companies like AEP.**

From the Regulator's Perspective:

As shown by this map, AEP covers 11 States in the U.S. Ohio is one of 7 States served by AEP in the Eastern region of the country.

AEP System



The Public Utilities Commission of Ohio website can be found at http://www.puc.state.oh.us/

From the Regulator's Perspective:

In its initial response filed with the Ohio Commission, AEP explained that all lines would be classified as transmission assets that operated at voltages that are designed to meet transmission standards.

- **All radial lines would be classified as "distribution," unless a line later became networked or changed its function and then it might be "reclassified" as a transmission facility.**
- **Regulators were very interested in how "reclassification" would be done, particularly if this led to any kind of cost-shifting or cross-subsidization.**

From the Regulator's Perspective:

The work of the State and the federal regulators in these unbundling efforts is made more compatible and somewhat easier by the use of a common "Uniform System of Accounts" or "USOA."

- **The USOA used for major electric utilities by both the federal government and State regulators across the U.S.A. is one designed by the FERC.**

- The USOA, published in the U.S. Code of Federal Regulations, Title 18, Volume 1, Parts 1 to 399, is available from the U.S. Government Printing Office. The last revision was April 1, 2002. The Uniform System of Accounts can be purchased from the US Government Printing at www.access.gpo.gov/su_docs/chklst/chklst.html or accessed free of charge at www.ferc.gov/electric/electric_USOA/electric_USOA.htm

From the Regulator's Perspective:

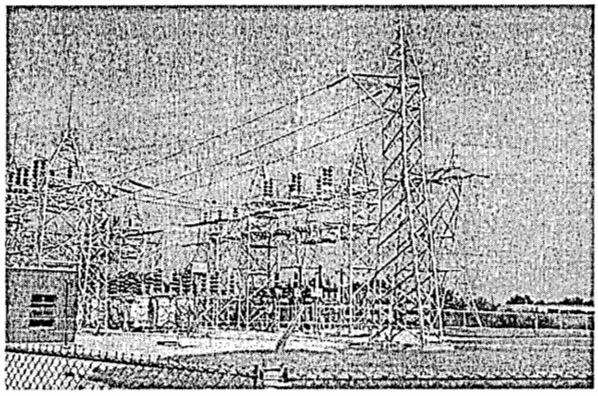
The USOA distinguishes assets with similar attributes with the use of unique account numbers, as follows:

1. **Steam Generation:**
   - Acct. 311 - Structures and Improvements
   - Acct. 315 – Accessory electric equipment
2. **Transmission Plant:**
   - Acct. 352 - Structures and Improvements
   - Acct. 353 – Station Equipment
3. **Distribution Plant:**
   - Acct. 361 – Structures and Improvements
   - Acct. 362 – Station Equipment

From the Regulator's Perspective:

•In its April 2002 Revision of the USOA, FERC made determinations regarding many of the "reclassification" issues, particularly where market conditions created questions about the use of facilities as a wholesale point of receipt or a delivery point to the ultimate end use customer.

•The facilities also included stations which change voltage from transmission to distribution voltages, regardless of who operates that part of the system.



You may have noticed the fence surrounding the station facility in the previous slide.

- I'd now like to turn this presentation over to Max Chau, Manager of the East Area Transmission Planning for AEP, who will take you behind that fence into the utility company to tell you more about AEP and to explain the steps he and his team members had to take to actually perform the task of "transmission unbundling."

AMERICAN ELECTRIC POWER COMPANY (AEP)

- Headquarters in Columbus Ohio, United States of America (State Capital of Ohio)
- Operates in 11 states in the USA, covering about 506,000 square kilometers
- About 5 million customers in the USA
- Owns assets in Australia, Brazil, China, Mexico, the Philippines and UK
- More than 23,0000 employees worldwide

AMERICAN ELECTRIC POWER COMPANY (AEP)

- Over 42,000 MW of Generation worldwide
- Over 39,000 miles of transmission lines
- One of the largest integrated electric utilities in the USA

Since 1996, AEP has offered an unbundled Transmission tariff for Wholesale Transmission Services. The following highlights AEP's experience in the transmission unbundling process

MAJOR STEPS TO UNBUNDLE TRANSMISSION

1) Identify assets that are booked in the Generation Production (G) accounts that perform primarily a Transmission (T) Ancillary service function. **Add** the incremental rate to recover for the cost of these assets to the Transmission tariff. (Already completed for wholesale unbundled transmission tariff.)

MAJOR STEPS TO UNBUNDLE TRANSMISSION

2) Identify assets that are booked in the Transmission (T) accounts that primarily serve a generation production Generation (G) function. **Subtract** the incremental rate that was used to recover the cost of these assets from the transmission tariff. (Already Completed for wholesale unbundled transmission tariff.)

MAJOR STEPS TO UNBUNDLE TRANSMISSION

3) Identify assets that are booked in the Transmission (T) accounts that primarily serve a Distribution (D) function. **Subtract** the incremental rate that was used to recover the cost for these assets from the transmission tariff. (In progress to develop retail access unbundled transmission tariff.)

MAJOR STEPS TO UNBUNDLE TRANSMISSION

4) Identify assets that are booked in the Distribution (D) accounts that primarily serve a Transmission (T) function. **Add** the incremental rate to recover the cost of these assets to the Transmission Tariff. (In progress to develop retail access unbundled transmission tariff.)

MAJOR STEPS TO UNBUNDLE TRANSMISSION

In essence: The unbundled transmission tariff should avoid cross-subsidization among Generation Production (G) Transmission (T) and Distribution (D) ratepayers.

EACH OF THE STEPS IN THE UNBUNDLING OF TRANSMISSION REQUIRES:

A. Well-founded technical and engineering basis for reclassification of assets

B. Available data and inventory of assets and process to obtain the desired accounting information

EACH OF THE STEPS IN THE UNBUNDLING OF TRANSMISSION REQUIRES:

C. Proper coordination with, and review and participation by the appropriate regulatory bodies

D. Pragmatic approaches including statistical analysis, assumptions and approximations to compensate for inaccurate or unavailable data as well as impractical data or accounting processes

UNBUNDLING OF (T) ANCILLARY SERVICES ASSETS FROM (G) ACCOUNTS

- **<u>Step 1</u> Clearly articulate and identify the technical and engineering basis for the reclassification of assets that were formerly included in the Generation Production (G) account that are primarily serving a Transmission (T) Ancillary Function**
  - In this case, the production of reactive power (also known as Volt- Amperes-Reactive or VAR) was identified as a Transmission Ancillary function. The following steps in the unbundling process identify the investments booked in the Generation Production accounts that are used in the production of VARs

UNBUNDLING OF (T) ANCILLARY SERVICES ASSETS FROM (G) ACCOUNTS

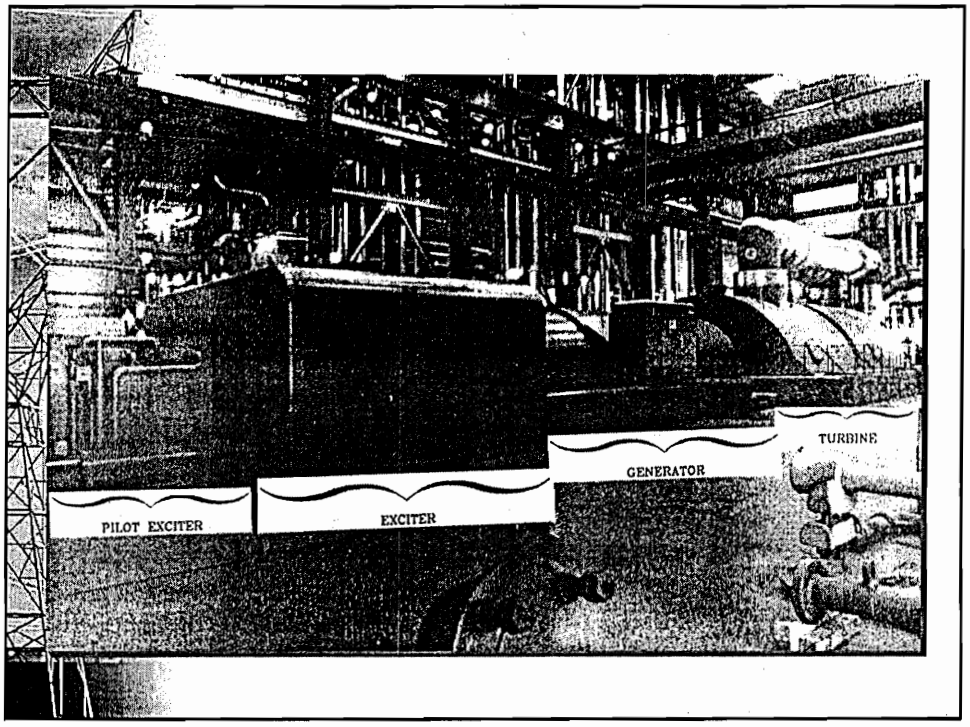
- **<u>Step 2</u> Examine availability and accuracy of existing accounting data to determine the proper process to "extract" the investments for equipment associated with the production of VARs. Although the FERC Uniform System of Accounts provides a general minimum framework for the accounting of assets, specific accounting information varies from plant to plant depending on the age of the plant and the specific operating company**

UNBUNDLING OF (T) ANCILLARY SERVICES ASSETS FROM (G) ACCOUNTS

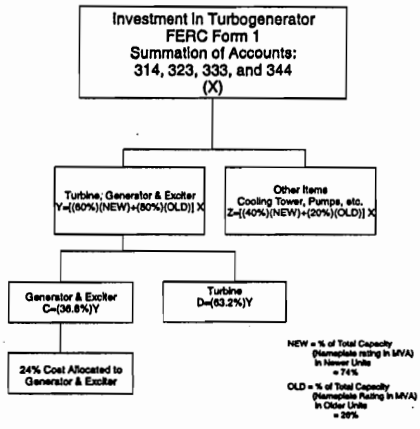
- Step 3 Review specific Generation Production FERC accounts to identify specific equipment used for the production of VARs. The excitation system in a power plant for example is used for the production of VARS

UNBUNDLING OF (T) ANCILLARY SERVICES ASSETS FROM (G) ACCOUNTS

- Step 4 Where available data is not sufficient to obtain the specific investments, engineering expertise is used to determine typical cost ratio of equipment needed to produce VAR to the overall plant investment. Apply the typical cost allocation to plants that do not have detailed accounting data



AEP Determination of Cost of Generator-Exciter



ASSUMPTIONS:

1. Allocate Investment in Turbine, Generator & Exciter and Other Items 60% : 40% for Newer Units and 80% : 20% for Older Units.
2. Allocate Investment in Turbine, Generator & Exciter 60.86% : 39.06% for Newer Units and Older Units. (Material)
3. Allocate 17.89% as Labor Cost for Turbine, Generator, & Exciter as Percentage of Turbine, Generator, & Exciter Material Cost.
4. Allocate 24% as Labor Cost for Generator & Exciter as Percentage of Turbine, Generator, & Exciter Labor.

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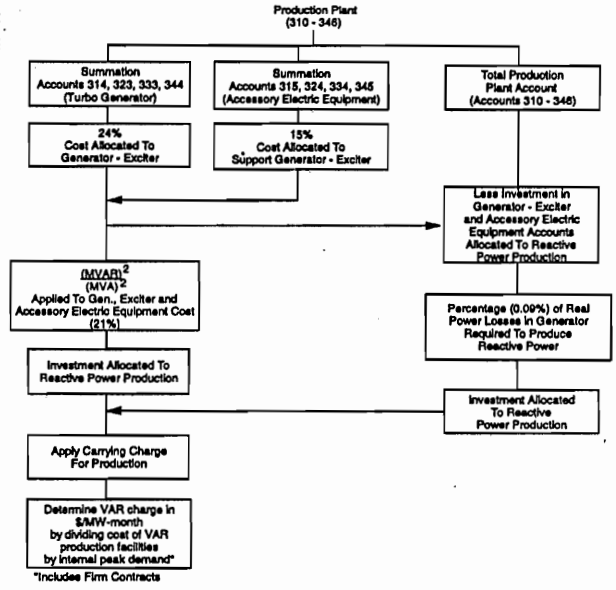
UNBUNDLING OF (T) ANCILLARY SERVICES ASSETS FROM (G) ACCOUNTS

- Step 5 Using the approved cost recovery tariff for transmission, develop the cost for the production of each VAR based on the total investment in assets used in the production of VARs

UNBUNDLING OF (T) ANCILLARY SERVICES ASSETS FROM (G) ACCOUNTS

- Step 6 Determine the amount of MVAR that needs to be produced for each MW of electricity that is transmitted across the AEP system. This will determine the incremental VARS charged to each transmission access customer for each Watt transmitted

AEP Methodology For Determining VAR Charge



UNBUNDLING OF GENERATION PRODUCTION (G) ASSETS FROM TRANSMISSION (T) ACCOUNTS

- Investment accounts of all transmission substations in AEP with generation connections were reviewed
- Investments of the Generator Step-up transformer, the generator leads and at least one of the high-side generator circuit breakers were identified for each transmission substation

UNBUNDLING OF GENERATION PRODUCTION (G) ASSETS FROM TRANSMISSION (T) ACCOUNTS

- If original investment cost was not available for the generation equipment at the transmission substations, reproduction cost adjusted for actual installation date was used
- The cost of these generation-related assets were removed from the Transmission rate base and added to the generation rate base

UNBUNDLING OF TRANSMISSION (T) AND DISTRIBUTION (D) ASSETS

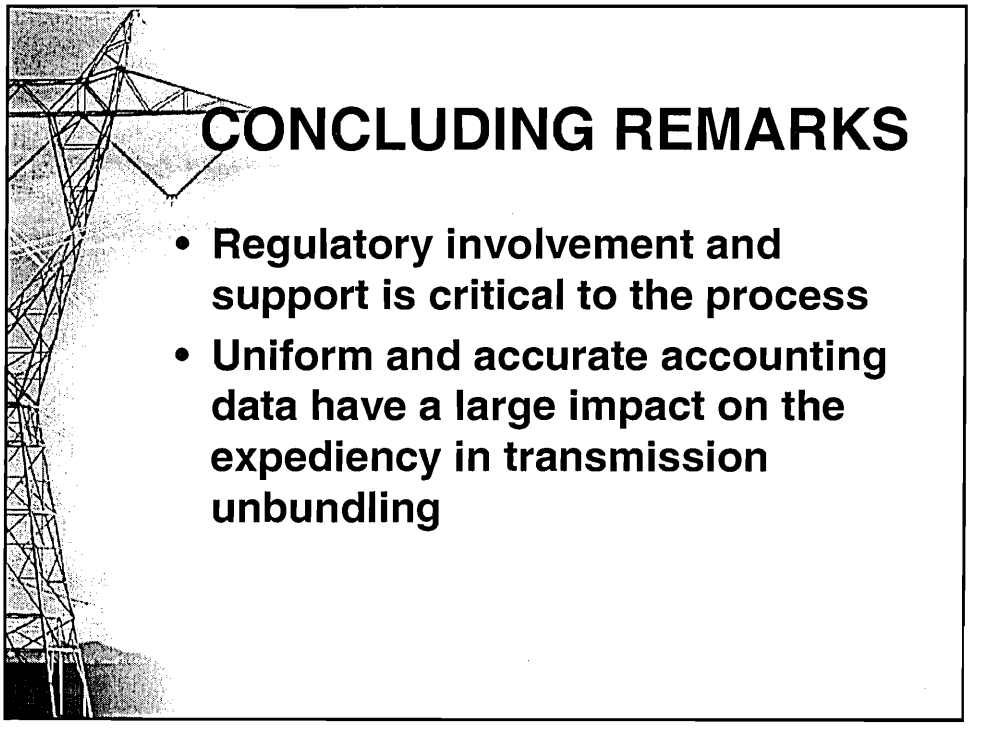
- Primarily driven to determine transmission and distribution tariffs for retail access
- FERC's Seven Factor test provides the general guidelines for T&D asset separation
- Regulatory commissions for all eleven states where AEP operates were consulted to ensure compliance with states' regulations as well

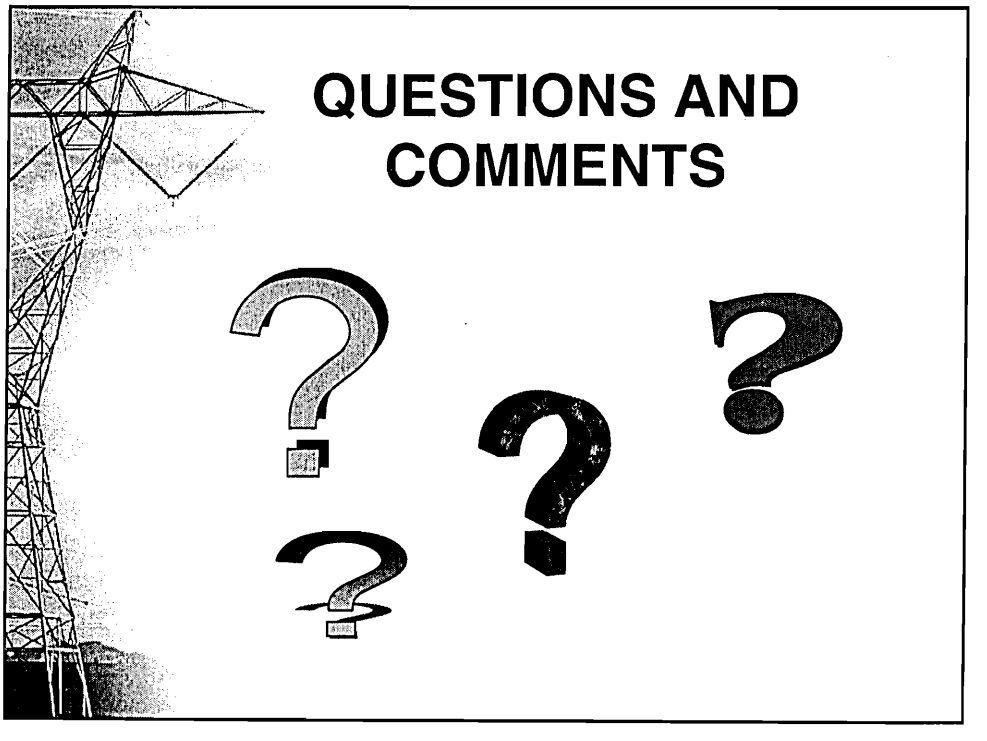
UNBUNDLING OF TRANSMISSION (T) AND DISTRIBUTION (D) ASSETS

- Process is data and analysis intensive since it requires detailed examination of several thousands transmission and distribution substations to segregate T and D assets for each and every station based on the rules developed by FERC and the state regulatory bodies

CONCLUDING REMARKS

- While the specific challenges in each phase of Transmission unbundling are different, the fundamentals of the process are the same
- Sound fundamental technical, engineering and cost causation principles must be used in the functional unbundling process


CONCLUDING REMARKS
• Regulatory involvement and support is critical to the process
• Uniform and accurate accounting data have a large impact on the expediency in transmission unbundling


QUESTIONS AND COMMENTS

3

HUNTON & WILLIAMS

Southeast Europe Regional Workshop

Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

James A. Schmidt
28 May 2003
Zagreb, Croatia

HUNTON & WILLIAMS

Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Summary

I. EU Requirements: Overview of Electricity Directive and Athens Memorandum

II. Requirements for Unbundled Accounts

A. EU Electricity Directive

B. Athens Memorandum

C. Why Unbundled Accounts?

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Summary (cont'd)

III. Requirements for Unbundled Transmission

A. EU Electricity Directive

B. Athens Memorandum

C. Why Unbundled Transmission?

IV. Proposed Amendments to EU Directive

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Athens Memorandum: Overview

Who?

Adhering Parties are Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Greece, Romania, Turkey, Serbia and Montenegro, FYROM, and Italy.

What?

Not law – Commitment to establish integrated regional energy market in South East Europe

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Athens Memorandum: Overview (cont.)

Why?

- Ensure integration into the European Union's Internal Energy Market

How?

- Consistency with European Union Directive 96/92 and any later amendments.

"This market will be based on the principles set out in the Electricity Directive." *Athens MOU, Article 1.*

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Electricity Directive: Overview

EU Directive 1996/92

Statement of many Principles, a few basic requirements, and "flexibility" provisions.

Focus on opening EU-wide borders for electricity trading, not internal markets.

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Unbundling Accounts

Unbundling Accounts: EU Directive

- REQUIRES: separate, unbundled accounts for generation, transmission, and distribution activities to allow transparent pricing of different activities.
  - EU Directive, Article 14
- DOES NOT REQUIRE: legal unbundling of utility companies. Utilities not required to split up or divest assets.

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Unbundling Accounts

Unbundling Accounts: Athens MOU

Requires separate accounts for transmission activities, distribution, generation, and supply.

- **"To ensure that integrated electricity undertakings shall ... keep separate accounts for their transmission, distribution, generation and supply activities, as they would be required to do if the activities ... were carried out by separate undertakings, with a view to avoid discrimination, cross-subsidization and distortion of competition.... Revenue from ownership of the transmission/distribution system shall be specified in the accounts."** *Athens MOU, Article 2(2)*

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Unbundling Accounts

Unbundling Accounts: Athens MOU (Cont.)

Energy sector regulatory authority is responsible for enforcing unbundled accounts.

- The national regulatory authority shall be responsible for "the effective unbundling of accounts to ensure there are no cross-subsidies between generation, transmission, distribution and supply activities." *Athens MOU, Section 1.1.2(f)*

Regulator to have access to accounting information for this purpose. *Athens MOU, Article 1.1.2(f)*

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Unbundling Accounts

Why Unbundle Accounts?

- Avoid cross-subsidization and enhance transparency
- Open Markets for cross-border Competition
- Enforcement
  - Audits as a solution?
  - Enforcement will be difficult — even with experienced regulators.

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Unbundled Transmission

Unbundling Transmission Tariffs: EU Directive

Requires States to choose model:

- Negotiated Access—system users must be able to negotiate their way onto the system so they can enter into voluntary agreements to sell/buy power
- Regulated Access—system users have right to access system, but must pay regulated tariff
- Single Buyer—one legal entity established for centralized buying and selling of electricity and management of the transmission system customers

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Unbundled Transmission

Unbundling Transmission Tariffs: Athens MOU

Open Access for Regional Market based on Transparent Transmission Tariffs

- Parties agree "[t]o implement a system of Regulated Third Party Access to the transmission ... systems based on published tariffs, applicable to all eligible customers and applied objectively and without discrimination between system users. *Athens MOU, Section 2(10):*

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Unbundled Transmission

Unbundling Transmission Tariffs: Athens MOU (cont.)

Tariffs to include non-discriminatory Connection and Access provisions

> "Regulatory Authorities shall at least be responsible for ... (a) connection and access to networks, including transmission ... tariffs."
> *Athens MOU, Article 1.1.2*

Regulated Access is Model #2 of EU Directive

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Unbundled Transmission

Why Unbundle Transmission Accounts to set Tariffs?

- Recognize "natural monopoly" Service.
- Set Tariffs to reflect cost of Transmission Service
- Prevent discrimination – for or against.
- Encourage Regional Market.
- Improve Efficiency?

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Potential Changes?

Amendments to EU Directive

Athens MOU provides agreement to accommodate changes to the EU Directive.

Proposed amendment to EU Directive still proposed, so not yet binding.

HUNTON & WILLIAMS

Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

Potential Changes?

EU Directive Amendment will have ***no effect*** on Athens MOU regarding Unbundling of Accounts

- The Athens MOU already incorporates – verbatim – the language of the propose EU Directive Amendment

  Compare Athens MOU, Article 2(2) against Proposed EU Directive Amendment Article ~~4~~ 19 (3)

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Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

EU Directive Amendment will have ***no effect*** on Athens MOU regarding Unbundling of Transmission Tariffs

- The Athens MOU already incorporates – verbatim -- the language of the proposed EU Directive amendment

  Compare Athens MOU, Article 2(10) against Proposed Amendment 16(1)

HUNTON & WILLIAMS

Requirements for Unbundled Accounts and Unbundled Transmission Tariffs

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4

Albanian's Efforts to unbundle its transmission tariffs and accounts.

- Albanian Electricity Regulatory Authority (ERE), actually is working based on actual law but the new law is in the last steps of approving procedures in Parliament. New law aim empowering the ERE to issue licenses and approve future market model, including export or import procedures. The ERE is also tasked to promote competition within the electricity sector.

- Albanian Power Corporation (KESH) is a vertically integrated monopoly utility and related to issues of unbundling, it is not yet defined the status. Actually KESH and ERE are working with SEETEC in order to define transmission tariffs and accounts.

- Currently, the ERE has no authority regarding the international market for the export or import of electricity. KESH, Albania's vertically integrated monopoly utility, deals with all export or import issues, subject to Albanian public procurement laws.

- The draft Law, by empowering the ERE to approve the market design and grid code, along with the issuance of licenses, creates the legal foundation with which other operators may engage in export or import activities in the future. The ERE is also tasked to promote competition within the electricity sector. Ultimately, it will depend upon the design of the market model chosen that determines whether and to what extent limits will be placed on market participants regarding the export or import of electricity.

- There is currently one bundled tariff in Albania, based upon the required revenues for the vertically integrated utility, KESH, to provide service. Hence, there are no separate transmission tariffs (but since 2000, the ERE has required KESH to submit its transmission costs when filing tariffs); access tariffs or procedures; targets and incentives; cross-border tariffs; or inclusion of stranded costs. KESH receives subsidies from the Government for certain categories of customers, including residential customers for the first block of 300 kwh/month.

- Under the draft Law, the ERE is responsible for setting tariffs and to establish targets and incentives to encourage efficiency in internal operations and management. In

anticipation of the passage of the draft Law, the ERE is in the process of educating its commissioners and staff regarding tariff methodology and rate setting procedures.

- The end of this year is foreseen as the date for unbundling of transmission tariffs

- We have not yet defined the accounts because of being vertically integrated company and therefore we have problems related transmission tariffs.

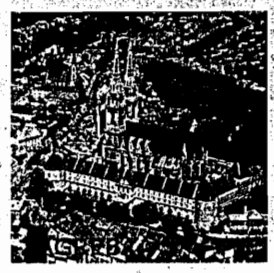
Those are some of the topics and status, related to the transmission tariffs and accounts in Albania, I am going to focus on, during my presentation.

Best regards,
Kastriot Sulka

5

VRED

Status Report on Development of Unbundled Transmission Tariffs in the Republic of Croatia



Croatian Energy Regulatory Council
Mićo Klepo, CERC Chairman/President

VRED

FRAMEWORK FOR ENERGY SECTOR REGULATION

- **The "package" of five energy laws:** ***Energy Law, Law on Electricity Market, Law on Gas Market, Law on Oil and Oil Derivatives Market , Law on Energy Activity Regulation (Around 40 law&by-law acts and other documents under elaboration).***
- **Croatian Energy Regulatory Council performs the following:**
  - **supervision and control of electricity, gas, heat and oil markets,**
  - **granting transparent and non-discriminatory performance of energy activities,**
  - **granting and suspending licenses,**
  - **ensuring transparent and non-discriminatory performance of activities,**
  - **approving and supervision of tariffs – regulated tariffs for natural monopolies and energy activities subject to public service obligation,**
  - **approving construction of power generation plants for tariff customers,**
  - **issuing decisions that grant the eligible producer status,**
  - **approving plans for the development and construction of network,**
  - **settlement of disputes.**
- ***Based on the standards set by the Regulatory Council's General Act CERC determines the transmission and distribution grid usage fees (Act is presently under discussion and postage stamp method is proposed).***
- ***The Law on Electricity Market establishes the conditions for a regulated TPA to transmission network.***

VRED

ELECTRICITY PRICES AND TARIFF SYSTEM

- Tariff systems shall be passed by the Croatian Government upon the proposal by energy subjects/operators on whose services the tariffs will be applied (based on the opinion obtained from the Ministry and CERC).
- CERC approves the methodology and supervises tariffs for monopolies (electricity transmission and distribution).
- Tariff customers shall have energy priced according to the tariff systems.
- CERC monitors the application of tariff systems.
- Eligible customers and suppliers freely negotiate the price.
- Equalized price of electricity for the same category of tariff customers.
- Establishment of real (cost reflective and initiative) tariffs and prices for generation, transmission, distribution, supply, system operation.
- Problem of stranded costs (the reconstruction of out-of-date and devastated grid parts, reestablishment of connections towards neighbours - 400kV TS Ernestinovo).

VRED

POWER SECTOR'S CONDITION AND MAIN ISSUES

- HEP - Power Utility is a state owned company.
- Restructuring of HEP is under way.
- HEP should unbundle its vertically integrated activities (generation, transmission and distribution/supply) into individual, legally independent companies (HEP Group).
- Independent system and market operator (ISMO) should be established.
- Electricity market structure under elaboration.
- Transmission and distribution networks' strategy, development and construction plans should be defined.
- Transmission pricing methodology is being prepared.
- Grid code and other documents and procedures are being prepared.
- A new all-inclusive Tariff System has been passed recently by the Government (*Tariff System for Power Activities Carried out as PSO*).
  - Some activities are experiencing a delay.
  - The first licence has been issued.

VRED

TRANSMISSION FEE REGULATORY FRAMEWORK

- Conditions and the manner of calculating connecting costs and their distribution on users that benefit from such connection shall be regulated by the Rules to be passed by the Minister.
- The System Operator shall prepare plans for the development and construction of the transmission network for a 3-year period, in cooperation with the energy operator carrying out electricity transmission and subject to prior approval of CERC.
- Plans shall comply with the Energy Strategy and the Implementation Program.
- CERC shall set electricity transmission fee upon the proposal of the energy undertaking carrying out transmission of electricity.
- The electricity transmission fee will be set on the basis of network development and construction plans.
- The data on availability of access to and use of electricity transmission network shall be public.
- When a power generator and a customer intend to conclude a contract on electricity delivery and/or supply, and cannot obtain access to the network, they can construct a direct line, subject to the CERC approval.
- Operation and management of the electricity transmission network shall be regulated by the Grid Code. Grid Code shall be drafted by the System Operator in cooperation with energy operators carrying out electricity transmission and distribution. The Grid Code shall be passed by the Minister subject to prior opinion of CERC.

VRED

Thank you for your kind attention.

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6

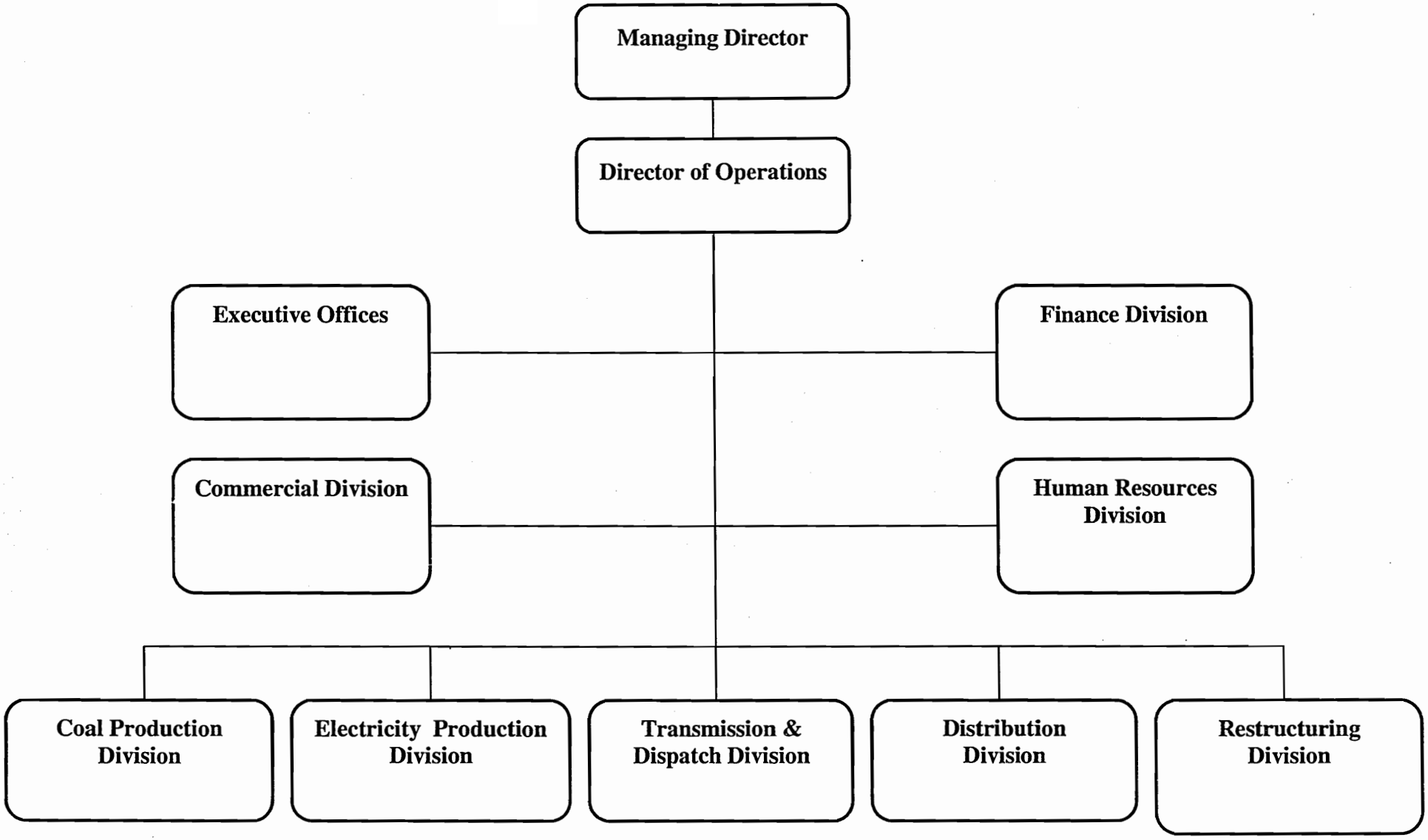
Kosovo – Energy Regulatory Office
Head of Office
Zekri Çarkaxhia

Report on the status of development of unbundled transmisission tariff

Korporata elektroenergjetike e Kosovës is the unique supplier of consume of Kosova with the electricity.
The Company is vertically integrated and has a unique external bank account.
Its core activity(coal production, production, transmission, distribution and sale of electricity) the Company make through the correspondent divisions.
Sales of electricity in the consume of Kosovo, the Company make according to the end users tariffs of electricity, approved by the government bodies of Company in charge.
The Company has not separated tariffs (production, transmission, distribution).
In order to implement the MoU, the Compay has started with the inicial undertakings of the unbundling process, wich consist on:

- Identification of the borders between divisions;
- Identification of the value of the assets of the divisions;
- Identification of inputs and outputs standards.

For that purpose has been engaged Cosortium SweedPower. According to the Action Plan of the Cosortium, the process of unbundling will be finalised at the end of 2004.
For the first time, in the Business plan 2003, the Company has established the internal commercial relations between the divisions, wich consist on establishment of the internal sales prices.
The main structure of the organisation chart of KEK is the following one:


Managing Director
Director of Operations
Executive Offices
Finance Division
Commercial Division
Human Resources Division
Coal Production Division
Electricity Production Division
Transmission & Dispatch Division
Distribution Division
Restructuring Division

7

STATUS OF DEVELOPMENT OF UNBUNDLED TRANSMISSION TARIFFS IN MACEDONIA

Dr Vesna Borozan

SOUTHEAST EUROPE REGIONAL WORKSHOP
ON
DEVELOPING UNBUNDLED
TRANSMISSION TARIFFS
May 27-29, 2003
Zagreb Croatia

Institutions for policy, regulation and system operation

- National Energy Authority
- Energy Regulatory Commission
- TSO/ISO
- Development of Unbundled Transmission Tariffs
  - Energy Regulatory Commission
  - USAID / NERA Project on Tariffs

Energy Regulatory Commission (ERC)

- 5 Commissioners
- ERC's competences
  - Establishment Tariff systems and Prices
  - Issuance / suspension of Licenses
  - Establishment of Grid Codes
  - Proposing and rendering opinions regarding all market rules
  - Customer protection

Development of unbundled transmission tariffs

- Unbundling of utility accounts of the Generation, Transmission and Distribution
  - ESM - management and accounting unbundling
  - Meinl Bank - Detailed action plan for the restructuring of ESM, including implementation of the accounting unbundling
- Unbundling of transmission tariffs
  - USAID and NERA – Unbundling Tariff Methodology and Calculation

Problems, dilemmas, concerns...

- Timeline
  - Energy Regulatory Commission – June 2003 !
  - Meinl Bank - Implementation of the accounting unbundling – December 2003 !?
  - USAID / NERA Project on Tariffs ???
  - Energy Regulatory Commission establishes Unbundled Tariffs ????
- Receivables collection ratio ?????

8

Development of Unbundled Transmission Tariffs in Romania

FLORIN GUGU
General Manager
Romanian Electricity & Heat Regulatory Authority

May 27-29, 2003, ZAGREB

KEY POINTS OF ELECTRICITY SECTOR REFORM

- **GEO 29/1998 approved by the Law 99/2000 and amended by the Law 789/2001 established ANRE as the regulatory authority whose mission is to "*create and implement appropriate regulations in order to ensure the good functioning of the energy sector under conditions of competition, transparency and consumer protection*"**

- **GEO 63/1998 on electricity and heat, promotes a competitive market in the electricity sector in order to meet: the social requirements for energy and fuel, the international commitments that Romania has assumed according to the Energy Chart Treaty, ratified by the Law 14/1997, the harmonization of the national regulations with the provisions of the community directives in the field**

May 27-29, 2003, ZAGREB

NETWORK ACCES

- Romania decided on a regulated system of access procedure, giving eligible customers the right of access to the transmission and distribution networks, based on the published tariffs
- Transmission system operator and distribution system operators deliver public services for all the network users, providing access to the networks for all applicants that meet the requirements of the law
- GEO No. 67/2000 The regulated tariffs are published by the competent authority in Romania's Official Gazette, and come into force 5 days after the publication date.

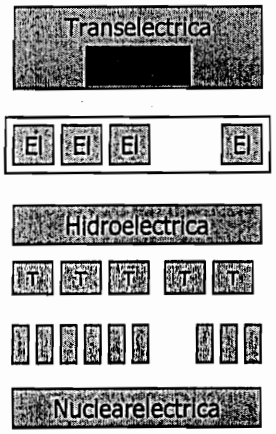
TRANSMISSION SYSTEM OPERATOR

- GD 627/2000 designates CN "Transelectrica" SA to operate as a transmission operator and a system operator and establishes its main field of activity.
- The main secondary legislation concerning TSO:
  - Commercial Code of the Electricity Wholesale Market
  - Technical Code of the Electricity Transmission Network
  - Regulation for the Romanian Power System Scheduling and Dispatch
  - Regulation regarding the Commercial Arrangements associated to the Unscheduled Electricity Exchanges with Other National Power Systems
  - The transmission and dispatching licenses conditions issued to CN "Transelectrica" SA

MARKET LIBERALISATION

- GD 122/2000: 8% market opening - E > 100 GWh/year
- GD 982/2000: 15% market opening - E > 100 GWh/year
- GD 1272/2001: 25% market opening - E > 40 GWh/year
- GD 48/2002: 33% market opening - E > 40 GWh/year

ELECTRICITY SECTOR PLAYERS



Transmission and system operator

Market operator

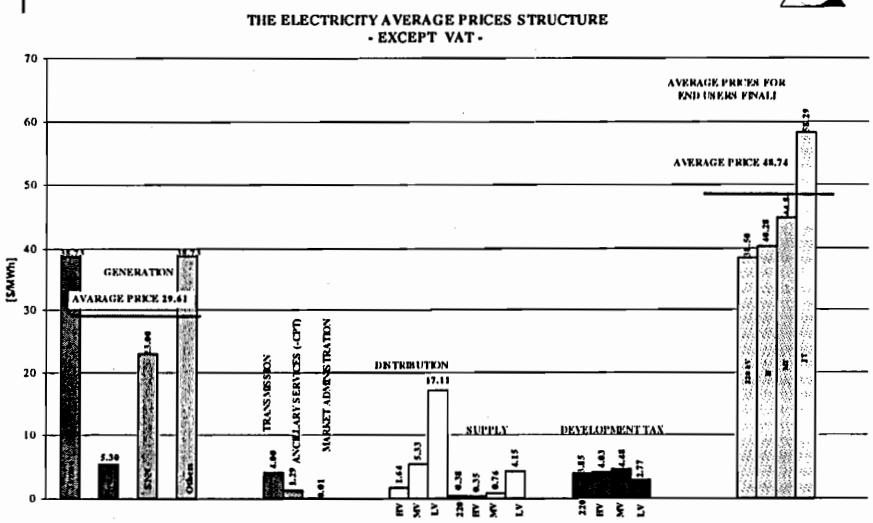
8 distribution and supply companies (to be privatized)

Generator - hydro power plants

Termoelectrica - thermal power

More than 20 municipal CHP's and IPP's

Generator - nuclear power plant



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REGULATED TRANSMISSION TARIFFS

- 14 zonal tariffs with two components:
  - injection component
  - extraction component
- Transmission charge is USD 4.0/MWh on average and does not depend on the electric paths and distances
- Nodal pricing
- REI-DIMO network reduction technique
- Based on SRMC including losses and congestion to establish efficient price signals

May 27-29, 2003, ZAGREB

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THANK YOU
FOR YOUR ATTENTION !

May 27-29, 2003, ZAGREB

9

Southeast Europe Regional Workshop On Developing Unbundled Transmission Tariffs

Ministry of Economy

Elektroprivreda Crne Gore A.D. Niksic

27 – 29 May, 2003

Dragan Bojovic
Deputy Minister of Economy
Republic of Montenegro

Introduction

The Athens Memorandum-2002 calls for the establishment of a regional electricity market in South East Europe and its integration into the European Union's Internal Electricity Market by 2005.

A key provision of the memorandum requires the development of a system of Regulated Third Party Access to the transmission network based on published tariffs, applicable to all eligible customers and applied objectively without discrimination between system users.

From 2002 the Electric Power Industry 0f Montenegro (EPCG) has been required to keep separate accounts for transmission, distribution and generation activities to complying with EU Directives and facilitating the unbundling process.

Elektroprivreda Crne Gore A.D.

- EPCG is responsible for all public electricity supply in Montenegro.
- It was established as a joint stock company in 1999.
- 62% of its shares are owned by the Government of Montenegro,
- 36% by private shareholders who received shares in 2001 under a Mass Voucher Privatization (MVP) scheme.
- 2% held by employees.

Montenegrin Power System

Total Generation Capacity 867MW
Hydro
Piva (342MW)
Perucica (307 MW)
Mini Hydro 8MW
Thermal
Pljevlja (210 MW).
Production 3,000 GWh
Imports 1,500 GWh

Montenegrin Transmission System

400 kV lines 249 km
220 kV lines 318 km
110 kV lines 656 km

System designed as integral part of the Balkan network

Energy Law Of Montenegro

- Is approved by the Government of Montenegro
- Draft sent Parliament on 29th April for passage into law
- Establishes an independent regulatory Agency
- Establishes a framework for the electricity market
- Allows for third party access, and supply competition
- Requires the functional unbundling of EPCG

Energy Regulatory Agency

- Established to regulate prices in areas where competitive markets do not exist.
- Issue licenses for Generation, Transmission, Distribution, Supply and Market Operations of electric power.
- Following establishment, the first rates setting hearings are expected to commence two years after the Energy Law comes into force.
- The ERA must establish a market operator, who will then prepare and submit rules for the participation in the energy market and a timetable for competition in the supply market.
- The ERA will promulgate rules and regulations on the competitive structure of the market for electricity.
- Effect compliance with European Union codes and requirements
- Agency will give SEER matters high priority

Unbundling of Transmission Tariff

- EPCG Accounts brought up to IAS standards for the financial years 2001 and 2002.
- EPCG Management Accounts now functionally unbundled
- EPCG currently has the basis for developing an unbundled transmission tariff
- EPCG will be unbundled in order to separate activities in line with EU directive i.e.
  - Generator
  - Transmission System Operator
  - Transmission and Market Operator
  - Distribution Operator
  - Supplier
- The timeframe for the unbundling of EPCG is 18 months after the Energy Law is passed

Transmission Costs

- At this time unbundled accounts show Transmission system costs of
- 17.1 Million Euro
- or 4.02 Euro MWh
- No transmission tariff published

Future Transmission Tariffs

- GoM expects:-
  - Primary charge to be based upon demand, not energy
  - Connection Charge to provide locational pricing signals for generation
  - Initially costs to be recovered from all users, including transit users
  - Tariff deigned to assist regional trading

Montenegro and SEER

- GoM fully committed to the Athens process
- Will work to catch up with leading participants
- GoM fully committed to integrating transmission network regionally

10

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Transmission Pricing – Principles and Practical Experiences

Dr. Konstantin Petrov

KEMA Consulting

USAD / USEA Workshop

Zagreb, May 2003

Contents (1)

1. Nature of Transmission Network
   - Regulated and Competitive Areas
   - Essential Facilities
2. Objectives and Methods
   - Pricing Objectives
   - Methods
   - Major Cost Components
3. Network Connections
   - Deep Connection
   - Shallow Connection

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Contents (2)

4. Average and Marginal Cost Pricing
   - Average Cost Pricing
   - Short Run Marginal Cost Pricing
   - Long Run Marginal Cost Pricing
5. Major Steps in Transmission Pricing Design
   - Fundamental Questions
   - Scope
   - Design
   - Price Calculation
   - Payment Liability

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Contents (3)

6. International Experience
   - Countries Review
   - England und Wales
   - Norway
   - Sweden
   - Germany
   - The Netherlands
7. Conclusions

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1. Nature of Transmission Network

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Competition and Regulated Areas

Networks will remain regulated areas

Areas of competition

Monopoly areas

Power generation

System Dispatching

System Services

Power Transmission

Wholesale Supply

Power Distribution

Retail Supply

Metering and Billing

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Role of Networks

- Access to Market means Access to Networks
- Networks exhibit natural monopoly characteristics
- Restricting Network Access using technical or price mechanisms means restricting competition
- Establishment of efficient access pricing is fundamental for competition evolution

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2. Objectives and Methods

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Objectives

- Allocative Efficiency
- Cost Coverage
- Transparency and Practicability
- Non-Discrimination

Pricing objectives are not congruent. Balance of the objectives is required to achieve appropriate pricing regime.

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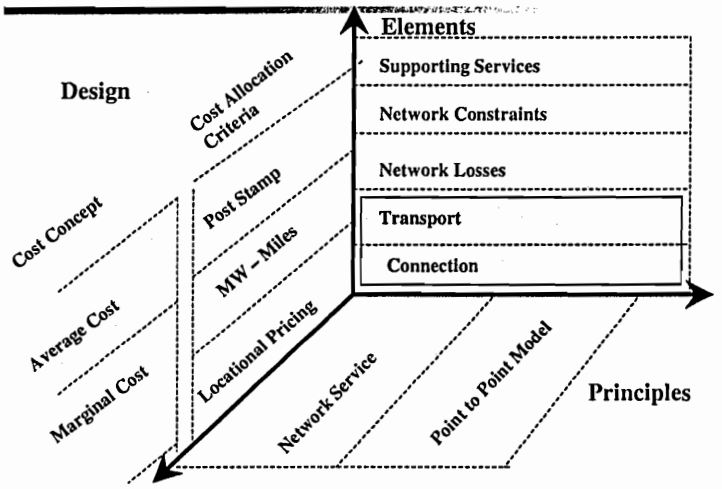
Approach and Methodology



Transmission pricing is a multi-dimensional issue that contains engineering, economic and accounting aspects.

10

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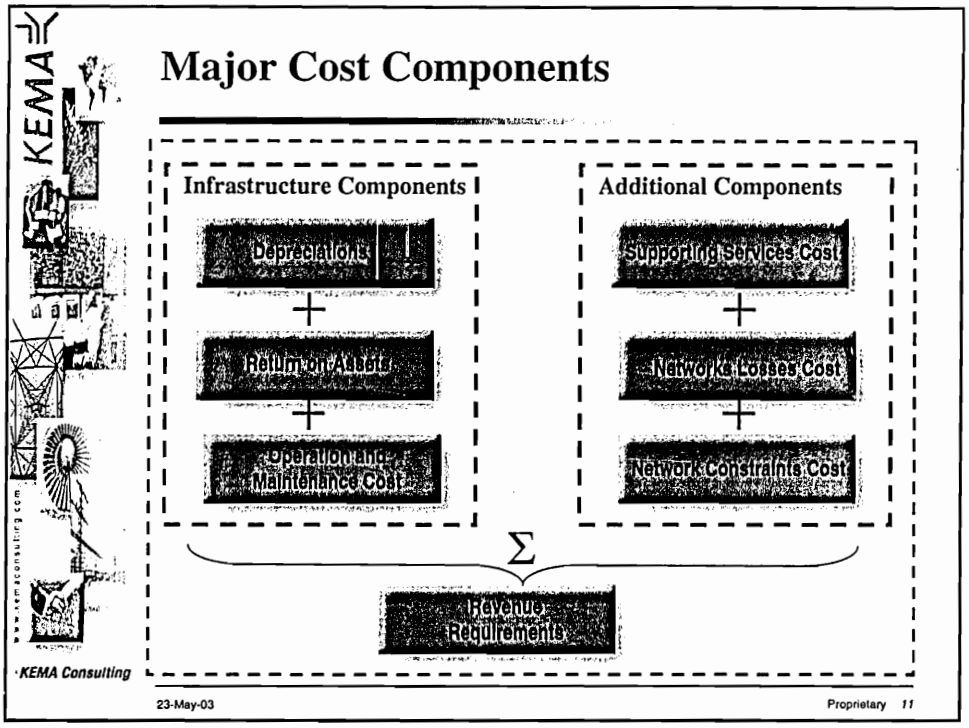

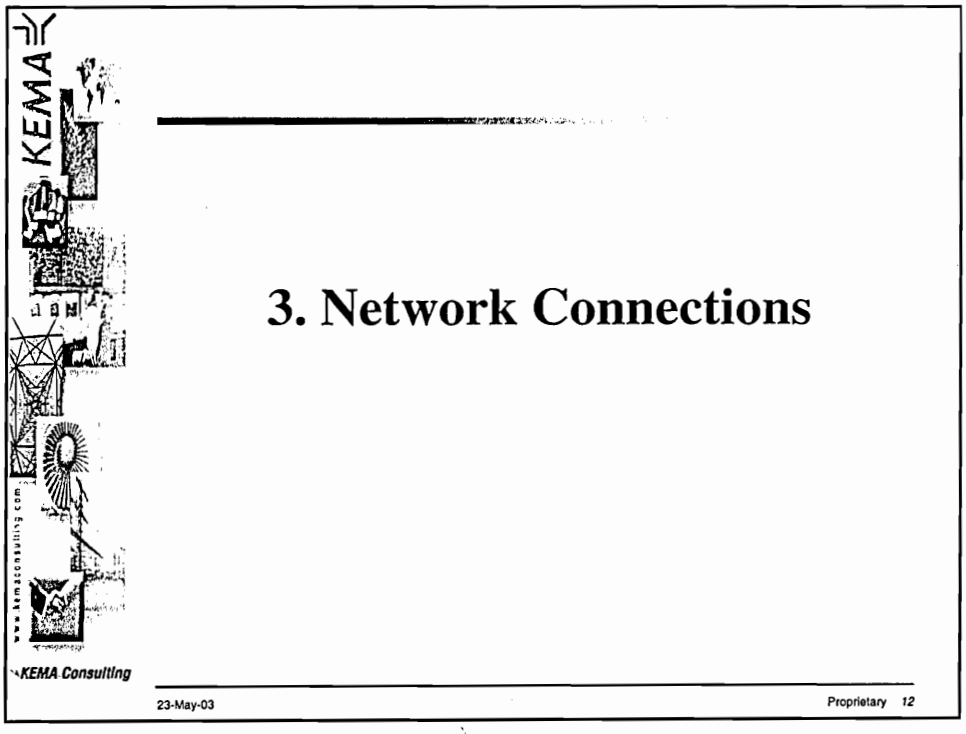

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Deep Connection

Deep Connection - Connection Charges cover network augmentation cost beyond the internal connection boundary between connection assets and core network assets.

- *Advantages*
  - follows closely the causality economic principles
  - avoids potentials for price increases for the existing consumers resulting from new connections
- *Disadvantages*
  - "deepness" of network augmentation arbitrary
  - determination of network augmentation costs burdensome
  - cost redistribution mechanism necessary to address the benefits of new customers connected after network augmentation has been done
  - high deep charges may prevent efficient entry

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Shallow Connection

Shallow Connection - Connection Charges cover the costs of directly attributable connection assets.

- *Advantages*
  - address directly attributable costs of connection assets
  - transparent and easy to implement
- *Disadvantages*
  - do not follow economic causality
  - no deep locational signals, however they could be establish via use of network charges

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4. Average and Marginal Cost Pricing

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Average Cost Pricing

Average Cost Pricing – based on the existing total cost allocated the units (energy or demand) transported via the networks.

- *Advantages*
  - costs easily identified
  - revenue requirements coverage and financial viability of network service providers ensured
- *Disadvantages*
  - do not create proper efficiency signals

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Marginal Cost Pricing

Marginal Cost Pricing – based on future cost necessary to transport one kW or kWh via the networks.

- *Advantages*
  - reflects the major economic rules and creates proper efficiency signals
- *Disadvantages*
  - derivation of marginal cost arbitrary
  - additional mechanisms to ensure cost coverage might be necessary

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Short Run Marginal Cost (SRMC)

SRMC Pricing – determine future cost necessary to transport one kW or kWh via the networks, given fixed capital stock (investments are not allowed). In case of electricity networks SRMC include network losses and network congestion cost.

- *Advantages*
  - creates proper short term efficiency signals
- *Disadvantages*
  - does not address locational signals in the network infrastructure
  - revenue raised by SRMC pricing not sufficient to cover cost
  - pure SRMC pricing could generate significant price fluctuations
  - allocation rules for congestion and transmission losses rentals arbitrary

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Long Run Marginal Cost (LRMC)

LRMC Pricing – determine future cost necessary to transport one kW or kWh via the networks, given flexible capital stock (investments are allowed).

- *Advantages*
  - creates proper long term efficiency signals
- *Disadvantages*
  - revenue raised by LRMC pricing not sufficient to cover cost
  - Determination of LRMC arbitrary

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Marginal Cost Pricing / Cost Coverage

Country	*Method*	*Cost Coverage (%)*
England and Wales	Long Run Average Incremental Cost	22 %
Australia	Long Run Average Cost	50 % (predefined, no explicit calculation of LRMC)
New Zealand	SRMC	10 %
Norway	SRMC	17.2 %
Chile	SRMC	10 %
US Estimate	SRMC	5 %- 20%
Bolivia	SRMC	3.6%

Source: Read, Transmission Pricing in New Zealand, 1997; Glende & Westre, Transmission Pricing in Norway; Rudnick, Presentation: Latin American Experience in the Restructuring of Electric Power; 1998. Federal Energy Regulatory Commission, The Recovery of Fixed Transmission Costs, 7 December 1997, NARUC-DOE National Electricity Forum; Powerlink; OFGEM and NGC Reports; ACCC and IPART Reports.

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5. Major Steps in Transmission Pricing Design

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Major Steps/ Fundamental Questions

Four fundamental questions should be answered to design Transmission Pricing:

Which elements are covered by Transmission Charges? →	Scope
How Transmission Charges look like? →	Price Design
How Transmission Charges are defined? →	Price Calculation
Who should Transmission Charges pay and how? →	Liability and Usage Definition

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Major Steps/ Scope

Classical Components of Transmission Pricing

- Core Transmission Network Assets → Use of Network Charge
- Transmission Connection Assets → Connection Charge

Optional Components of Transmission Pricing

- *Transmission Losses*
- *Ancillary Services*
- *Transmission Constraints*

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Major Steps/ Design

Two principles are fundamental:

- Assets used individually should be covered through individual charge imposed to the users → Causality Principle
- Assets used jointly should be covered through contribution from all users → Common Good Principle

Transmission Charges Structure

- Use of Network Charge
- Connection Charge

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Major Steps/ Price Calculation / Overview

Two question should be answered:

Which are the cost to be covered by the Use of Network Charge	→ Evaluation of Revenue Requirements
How these assets should be allocated to Users	→ Cost Allocation Concept

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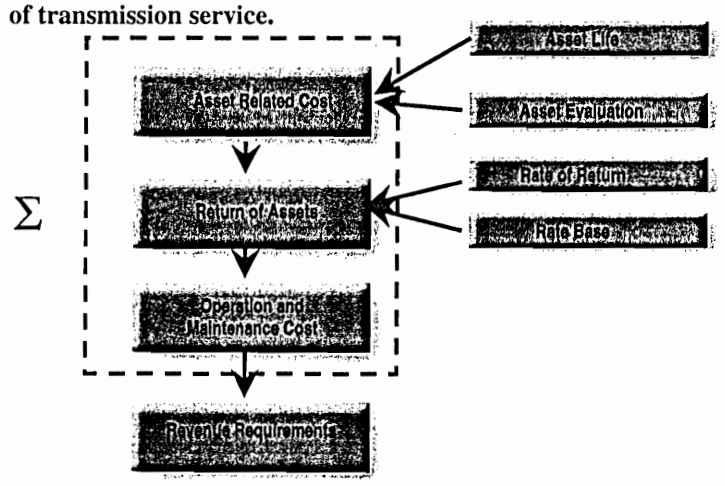
Major Steps/ Price Calculation / Determination of Revenue Requirements

Revenue requirements cover costs incurred by the transmission service provider in the process of provision of transmission service.



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Major Steps/ Price Calculation / Cost Allocation (1)

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Cost Allocation – In Time and Space

	Time Differentiation	Spatial Differentiation	Pro Rata Allocation
Concept			
Rationale	-Create proper locational economic signals - Reflect time dependence nature of transmission network cost - Complex and sometimes not transparent	- Create proper locational economic signals - Reflect locational dependence nature of transmission network cost - Complex and sometimes not transparent	- Simple but it does not create proper economic signals
Implementation	- Marginal loss factors and adjusted nodal prices - Timely differentiated component in transmission pricing (could include losses and congestion but also infrastructure)	- Marginal Loss Factors and adjusted nodal prices -Geographically differentiated component in transmission pricing	-Post Stamps

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Major Steps/ Price Calculation / Cost Allocation (2)

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Cost Allocation – To Load and Generation

	Only Load	*Generation and Load*
Concept		
Rationale	-Demand side is less elastic than generators - The loss of load causes higher cost on the demand side than on the generators side - Load id always the final payer	- Generation and load use the network (for transport and security purposes) and should pay - Create signals in the locational decisions of the generators - Generators need the network to gain from electricity sales. In case of non-reliable network they will incur opportunity cost. Hence, they should pay for using network
Implementation	Germany, Australia	Norway, UK, the Netherlands

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Major Steps/ Payment Liability/ Overview

Two Question Should be Answered

Who will pay for the Network Usage? → Payment Liability

All the partied using network should pay

How will be the usage defined? → Usage Definition

KW, KWh or fixed charge

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6. International Experience

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Countries Review

Cost Allocation Criteria

- Post Stamp
- MW - Miles
- Locational Pricing

Cost Concept

- Average Cost
- Marginal Cost
  - Long Term
  - Short Term

- E&W (Investment Cost Related Pricing)
- Australia (Cost Reflective Network Pricing)
- Germany (VV2), the Netherlands
- Norway, Latin America
- USA

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England and Wales / General Concept

- Separation of Supply and Network Service
- Network Service Model
- Use of Network Charge and Connection Charge
- Investment Cost Related Pricing based on Long Run Average Incremental Cost
- Zonal Transmission Use of System Charges (14 Generation and Demand Zones)
- Payments Liability for Transmission Use of System Charge 25 % Generators and 75 % Suppliers
- Individual Connection Charge Price Control via Licensing Regime (OFGEM)

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England and Wales / Investment Cost Related Prices

Investment Cost Related Pricing (ICRP)

Step 1: Determination of Expansion Rate based on the network investments (valued at Replacement Cost) and annuity factors £ /MW.km

Step 2: Optimization of the existing network using linear programming / Transportation Problem - Minimum Spanning Tree

Step 3: Determination of Long Run Marginal Cost (approximated through Long Run Average Incremental Cost) per Node

Step 4: Aggregation of Nodal prices in Zonal Prices

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Norway / General Concept

- Separation of Supply and Network Service
- Network Service Model
- Variable Charges based on Short Run Marginal Cost
  - Energy charge – Marginal Transmission Losses
  - Capacity Charge - Congestion Cost
- Fixed Charges
  - Connection Charge - covers the system security cost
  - Power Charge - residual element to balance the revenue requirements
- Zonal Energy Charge – 5 geographic zones and 3 time periods
- Congestion Management based on Market Splitting
- Payments Liability divided between Generators and Load
- Regulatory Price Control (NVE)

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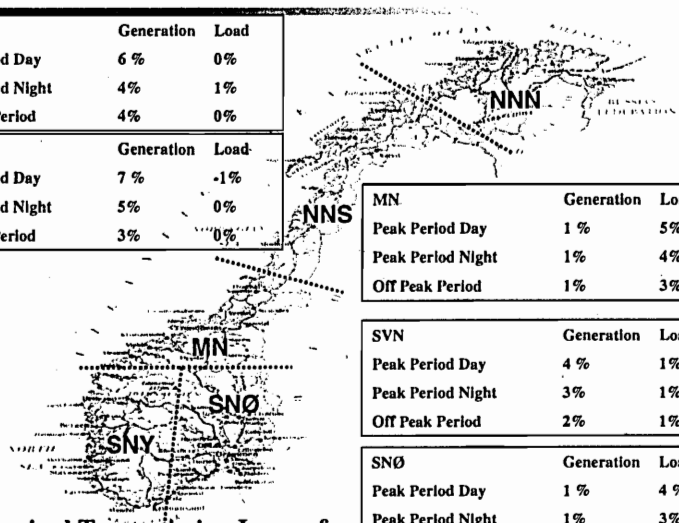
Norway / Marginal Transmission Losses

NNN	Generation	Load
Peak Period Day	6 %	0%
Peak Period Night	4%	1%
Off Peak Period	4%	0%

NNS	Generation	Load
Peak Period Day	7 %	-1%
Peak Period Night	5%	0%
Off Peak Period	3%	0%



MN	Generation	Load
Peak Period Day	1 %	5%
Peak Period Night	1%	4%
Off Peak Period	1%	3%

SVN	Generation	Load
Peak Period Day	4 %	1%
Peak Period Night	3%	1%
Off Peak Period	2%	1%

SNØ	Generation	Load
Peak Period Day	1 %	4 %
Peak Period Night	1%	3%
Off Peak Period	1%	2%

Marginal Transmission Losses for 5 geographical and 3 time zones

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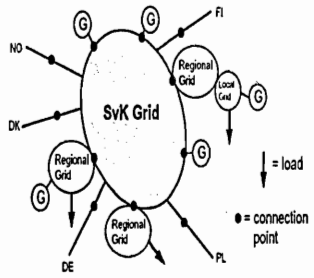
Sweden/ Overview

- Separation of Supply and Network Service
- Network Service Model
- Energy charge – 50 % of revenue, locational and time differentiation based on marginal transmission losses
- Capacity charge – 50 %,locational differentiation based on geographical latitude

Swedish grid structure



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Sweden/ Energy Charge

Energy tariff

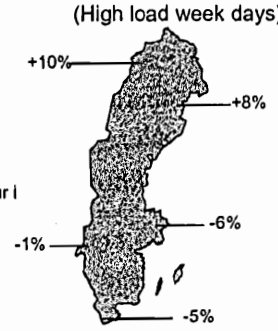
Yearly energy tariff =

$$\sum_i MLC \cdot E(i) \cdot P_E(i)$$

Energy hour i
+ = input
- = output

Energy price hour i

Marginal loss coefficients (MLC) (High load week days)



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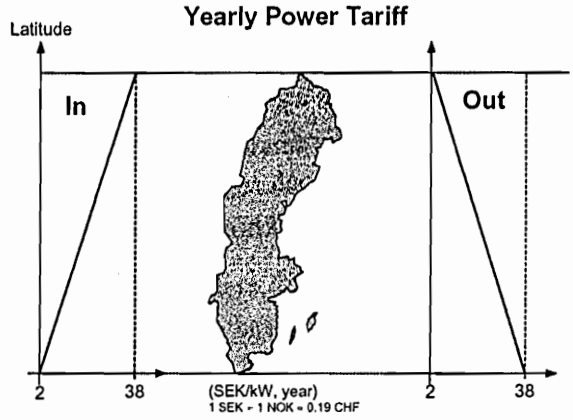
Sweden/ Power Charge



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Germany / General Concept

- Separation of Supply and Network Service
- Network Service Model (Point Tariffs) based on Post Stamp
- Cascading Model of Network Pricing
- Load Profiling for Small Consumers
- Transmission Pricing Regime is defined in the Association Agreement between VDEW, BDI and VIK
- Rules of Association Agreement are not binding legally, they are voluntary agreement
- Regulatory Control – only ex post by the Antimonopoly Office

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Germany / Overview

- Transaction independent Network Service Tariffs
- Network Service Tariffs include:
  - Use of Network
  - Ancillary Services
  - Network Losses
  - Concession Fee
  - German Specific Elements (taxes and concession fees)
- Cost Cascading
- Capacity and Energy Charge dependent on:
  - Connection Point (Voltage Level)
  - Peak Demand (MW)
  - Energy Consumption (MWh)
- Application of standard load profile for small consumers without demand measurement (synthetic and analytical load profiles)

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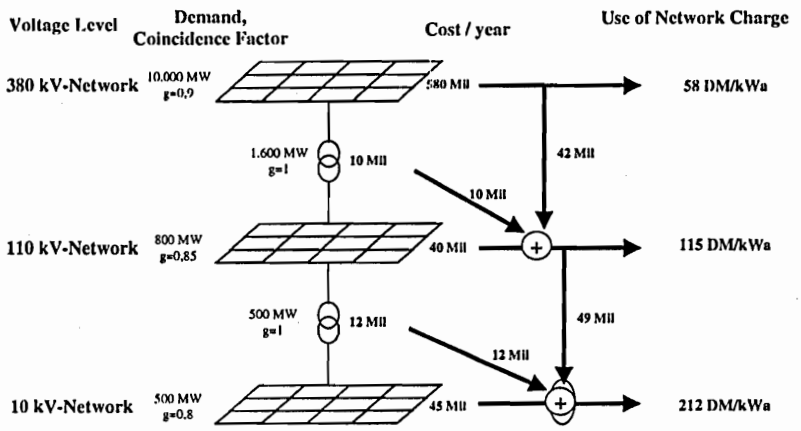
Germany / Cascading Model

Cascading - Costs of higher network levels are forwarded to the lower network levels



e.g. Network Charge for 110 kV-Network:
[58 DM/kWa x 0,9 x 800 MW + (20 Mil/a / 1600 MW) x 800 MW + 40 Mil/a] / 800 MW = 115 DM/kWa

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Germany / RWE Net Network Charges

Use of Network Charges

	Jahresbenutzungsdauer < 2500 h/a Leistungs- preis €/kWa	Arbeits- preis ct/kWh	? 2500 h/a Leistungs- preis €/kWa	Arbeits- preis ct/kWh	
Höchstspannungsnetz		3,52	0,89	21,52	0,17
einschl. Umspannung		7,98	0,89	25,98	0,17
Hochspannungsnetz		5,93	1,42	34,43	0,28
einschl. Umspannung		14,31	1,42	42,81	0,28
Mittelspannungsnetz		9,44	2,29	55,19	0,46
einschl. Umspannung		24,01	2,29	69,76	0,46
Niederspannungsnetz		13,07	3,51	76,82	0,96

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The Netherlands / General Concept

- Implemented on 1-1-2000
- basic structure:
  - point-tariff
  - cascading from HV -> LV
  - connection service charge and transmission service charge
- costs are allocated to G & L for HV and to L only for MV/LV
- different tariff carriers are used:
  - kWh consumption,
  - kWh generation,
  - kW contracted and
  - kW measured peak
- Regulatory control via Tariff Code and Regulatory Office Dte

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The Netherlands / Overview (1)

- 220 - 380 kV: 50% of costs is allocated to system service tariff, charged to all consumers (gross kWh consumption)
- 110 kV - 380 kV:
  - 25% of costs allocated to G (incl. import)
  - 75% to lower voltage levels
- G-tariff: kWh-delivery to network
- L-tariff: next slide

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The Netherlands / Overview (2)

- L-tariff has following tariff carriers:
  - 25 kV and up:
    - 50 %: kW contracted transmission capacity
    - 50 %: kW monthly peak
  - 1-20 kV:
    - 25 %: kW contracted capacity
    - 25 %: kW monthly peak
    - 50 %: kWh take
  - 0.4 kV
    - 16 %: kW contracted capacity
    - 84 %: kWh take

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Conclusions

- Transmission pricing design is a complex topic including engineering, economic and financial aspects
- A wide range of pricing models exist and no universal answer could be found
- Usually Use of Network Charge and Connection Charge are calculated and imposed separately
- Post Stamp concept is often used due to its simplicity, transparency and practicability
- A number of different pricing models based on marginal costs exist including also adjustment mechanisms to ensure revenue requirements coverage

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Southeast Europe Regional Workshop on Developing Unbundled Transmission Tariffs

Western European Case Study: Spain

Manuel Velasco
Senior adviser of Regulation and Studies department
RED ELÉCTRICA DE ESPAÑA
Zagreb, may, 28th 2003

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Summary

- Regulatory framework of Transmission in Spain
- Developing Revenue Requirement
- Reporting to the Regulatory Authority
- Network charges in Spain

Appendix: Standard costs for transmission facilities

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Regulatory framework of Transmission in Spain

The Spanish electricity sector reform

Regulatory framework evolution

- 1984-1997 ➡ Law on Unified Operation
- 1998-..... ➡ Act 54/1997, of electric power system

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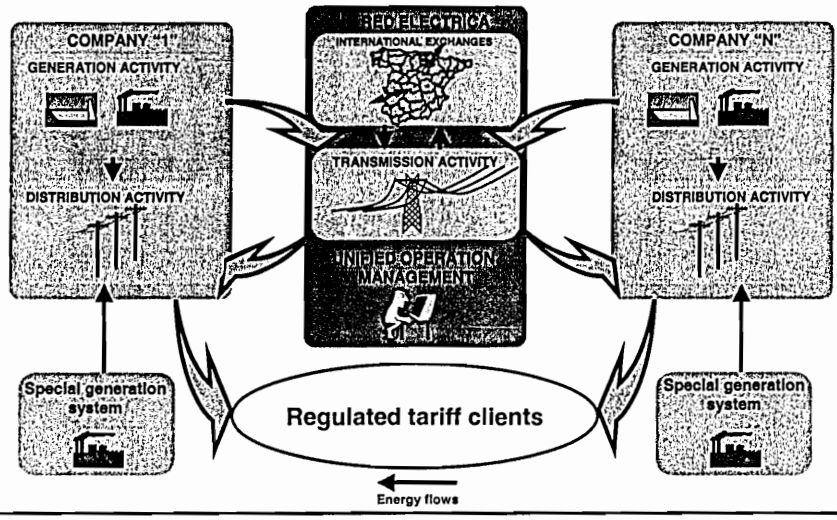
Regulatory framework of Transmission in Spain

The Spanish electricity sector reform

Law on Unified Operation (1984)



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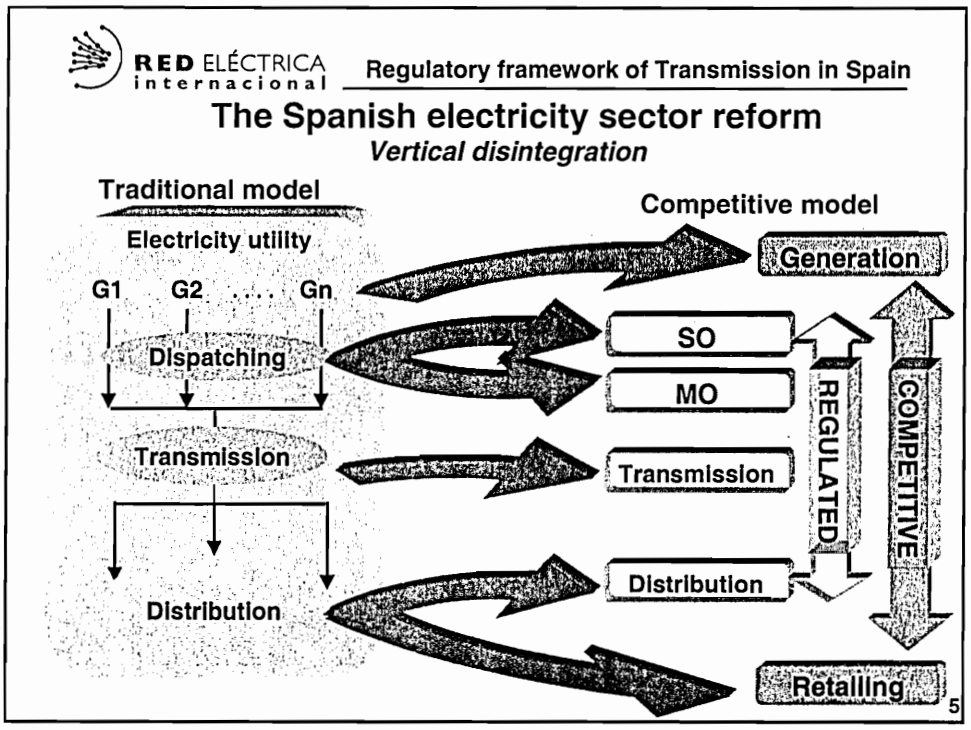

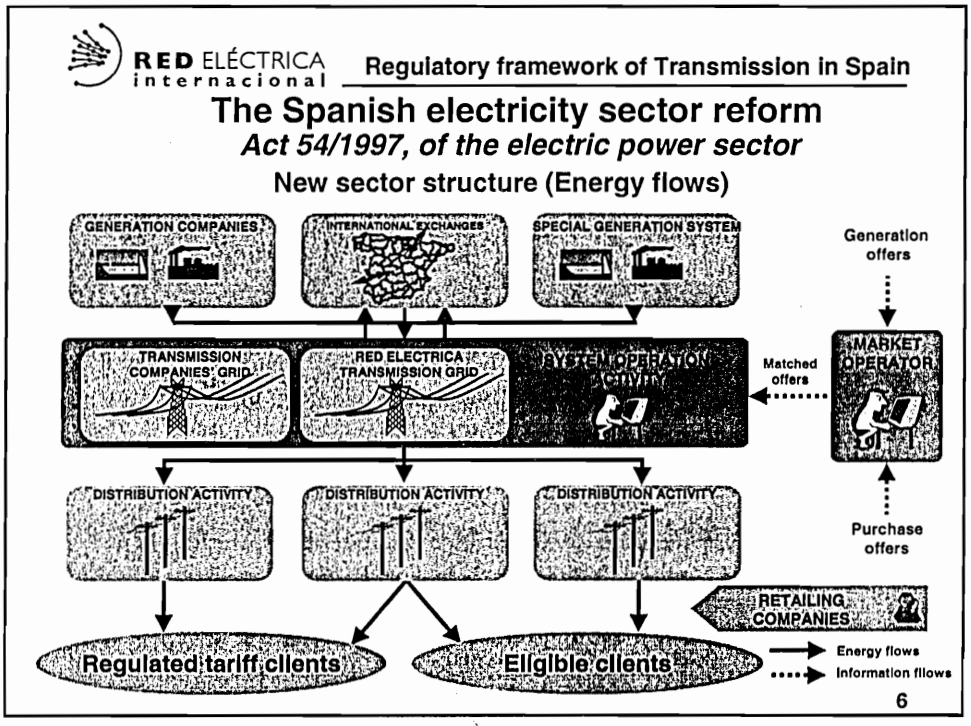

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Transmission in the current regulatory framework

- Binding Planning, carried out by Government
- Third Party Access:
  - ✓ May only be refused if necessary capacity is not available
  - ✓ Reserve of capacity not allowed
  - ✓ System Operator in charge of managing TPA
- Regulated Access Tariffs
- Regulated retribution
- Options for transmission installations constructions:
  - ✓ Authorisation
  - ✓ Tender procedure
- Legal unbundling with liberalized activities

Transmission is considered a natural monopoly

Scope of Transmission activity in Spain

- Lines in a voltage equal or over 220 kV
- International interconnectors, regardless the voltage
- Busbar connections in a voltage equal or over 220 kV
- Transformers 400 kV/220 kV.
- Any other active or reactive power control element connected in 400 and 220 kV and those connected to tertiary in transformers
- Interconnectors with power system located on islands or outside the peninsula and inter-island connections
- Other assets, determined by Ministry of Economics under proposal by system operator, considered as transmission
- Assets involving communications, protection, control, auxiliary services, land, buildings and other auxiliary items, whether electrical or not, required for the proper operation of specific transmission grid installations

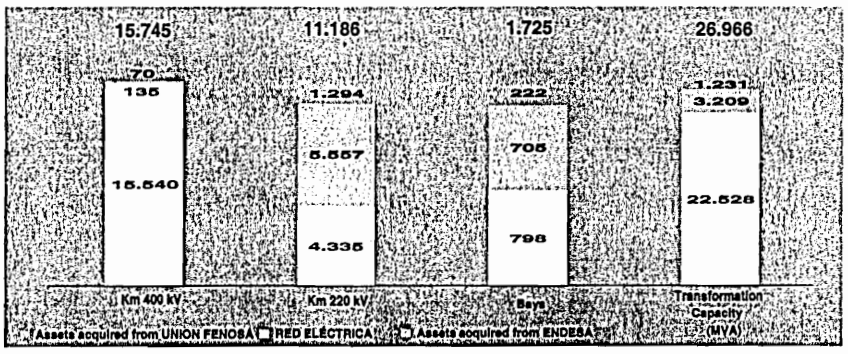
Unbundling of Transmission

The companies which carry out activities which are subject to the regulations have articles of association which limit their object to the former (transmission and distribution) and therefore cannot indulge in production or marketing activities.

	Production	Transmission	Distribution	Marketing
Production		LEGAL SEPARATION	LEGAL SEPARATION	SEPARATE BOOKS
Transmission			SEPARATE BOOKS	LEGAL SEPARATION
Distribution				LEGAL SEPARATION
Marketing				

Companies carrying out Transmission

Comparison before/after recent operations



RED ELÉCTRICA is the owner of 84% of transmission network

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Summary

- Regulatory framework of Transmission in Spain
- Developing Revenue Requirement
- Reporting to the Regulatory Authority
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Appendix: *Standard costs for transmission facilities*

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Development and charge of transmission costs

Tariff level → Revenue requirement

↑ Settlement ↓

Tariff structure → Access Tariffs & Integrated tariffs

Principles of revenue requirement development and charge

- Fixed by Government (Ministry of Economics)
- Based upon standard costs
- Payment guaranteed
  - ✓ Do not exist unbundled transmission tariffs
  - ✓ Transmission revenue charged in:
    - ◆ Regulated integrated tariff
    - ◆ Regulated access tariff
  - ✓ Distributors collect tariffs and, therefore, transmission revenues
  - ✓ Settlement procedure, conducted by CNE, to redistribute incomes collected by distributors

Methodology summary

- Differentiated treatment for
  - ✓ Facilities commissioned before 31/12/1997
    - ◆ Price-cup with updating rate
    - ◆ Efficiency factor included
  - ✓ Facilities commissioned since 1/1/1998
    - ◆ Individualised treatment trough standard cost, except for dispatching assets
    - ◆ Investment, maintenance and overhead and working capital costs remunerated
    - ◆ Tender procedure for allocation allowed
- Incentive scheme based upon facilities availability

Retribution methodology general formula

Transmission remuneration (Tr_{In}) for company "I" in the year "n":

$$TR_{In}=TR_{1998In}+IINT_{In}+Id_{In}$$

Where:

TR_{1998In}: Retribution of the whole of facilities commissioned before 31/12/97

$$TR_{1998In}= TR_{1998I} \prod_{1998}^{n}(1+IPC_n-X_n)$$

TR_{1998I} : Price-cap of the company "I" (507 millions € for all the companies)
X_n : Efficiency factor

$IINT_{In}$: Retribution of facilities commissioned before 31/12/n-1

$$IINT_{In} = IINC_{In}+IIND_{In}$$

$IINC_{In}$: Retribution of assets built under tender procedure since 1/1/1998
$IIND_{In}$: Retribution of assets built by direct regulator instruction since 1/1/1998

Id_{In} : Incentive for facilities availability

Retribution of facilities after 1/1/1998

- Facilities built under a tender procedure ($IINC_{In}$)

Aggregation of the retribution of facilities commissioned until year n-1, each calculated according to the tender award conditions

- Facilities built by regulator direct instruction ($IIND_{In}$)

$$IIND_{In}=iind_n+ IIND_{In-1}(1+IPC_n-Y_n)$$

donde,

$iind_n$: Retribution of facilities commissioned in year n-1
$IIND_{In-1}$: Aggregation and successive updating of iind corresponding facilities commissioned since year 1998 until year n-2
Y_n : Efficiency factor

Retribution of facilities after 1/1/1998

Retribution of facilities commissioned in year n-1 ($iind_n$)

$$iind_n = CIT(n)+CET(n)$$

- Investment cost CIT(n) consists of a depreciation component A(n) and a return on investment component R(n), both calculated on the standard investment gross value:

$$CIT(n) = A(n) + R(n) = VAI(n)/VU + VAI(n)*Tr_n$$

where,
VU : facility lifetime (40 years, except for dispatching centres which is 14)
Tr : Rate of return determined by the Ministry of Economics for a maximum period of 4 years

- Total Operation costs CET(n), obtained by aggregating operation and maintenance costs Com(n), and overhead and working capital costs Cea(n)

$$CET(n) = Com(n) + Cea(n)$$

where:

Com(n) is calculated by unit standard costs applied to bays and km.

and $Cea(n) = Com(n) * 0,07$

Availability incentive scheme, Id_{in}

Incentive scheme calculated on the availability of lines, transformers and reactive control compensators (all assets, whether before or after 1998), as follows

$$ID_{in=} = d_{in}(TR_{1998in}+IINT_{in})$$

where,

$$d_{in}=k(dr_{in}/do_{in}-1)$$

where,

k : Factor currently fixed in 1 (can be changed by Ministry)

dr_{in} : Actual availability

do_{in} : Target availability

A cap of 3% on top of the revenue allowed but not a collar

Retribution of a new facility (example)

Unit standard costs (MPTA/bay)	1998	1999	2000	2001	2002
Capital investment	270,66	274,72	278,84		
Operation and maintenance	13,27	13,40	13,53		

1+0,75*IPC; 1+(IPC-Y)

Substation X :
- Year of commissioning : 1999
- Number of bays : 3

- **Investment cost (CIT):**
  - VAI: 278,84 * 3=836,5MPTA
  - Depreciation (A=VAI/lifetime): 836,5/40=20,9MPTA
  - Return on investment (R=VAI*Tr): 836,5*0,04=33,5MPTA
  - CIT = A + R: 54,4MPTA
- **Total operation costs (CET):**
  - Operation and maintenance (Com): 13,53 * 3=40,5MPTA
  - Overhead and working capital (Cea = Com * 0,07): 40,5 * 0,07=2,8MPTA
  - CET = Com + Cea: 43,3MPTA
- **Total retribution of substation X(Iind = CIT+CET) :** 97,7MPTA

1+(IPC-Y)

98,6MPTA 99,5MPTA

Other transmission facilities' remuneration

Retribution of dispatching and energy control centers

- The VAI(n) is calculated by updating to the year n the accounting investment of year n-2 (VEI(n-2))

$$VAI(n)=VEI(n-2)(1+Tr_{n-1})(1+0,75IPC_{n-1})\ (1+0,75IPC_{n})$$

Retribution for special facilities

- Regulator (Ministry of Economics) will determine the remuneration methodology and lifetime for facilities with special characteristics
- i.e. Underground lines in a voltage of 400 kV

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Developing Revenue Requirement

Controversial items of the methodology

- Regarding facilities commissioned before 1998
  - ✓ Close down facilities not taken out of the pool
  - ✓ Not reduction of revenue for amortised facilities that expand its lifetime
- Regarding facilities commissioned since 1998
  - ✓ Methodology results in over-recovery of standard gross value
  - ✓ Absent of tenders for new facilities
- Reduction of retribution due to other incomes from non-electrical activities

→ ***CNE claims***

- Treatment of deviation of parameters
- Standard values are obsolete
- Costs not included in standards

→ ***REE claims***

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Developing Revenue Requirement

Controversial items of the methodology

CNE claims		***REE's opinion***
■ Regarding facilities commissioned before 1998 ✓ Close down facilities not taken out of the pool of assets before 1998 ✓ Not reduction of revenue for amortised facilities that expand its lifetime	→	■ Retribution system based upon service given ■ Renovation and Upgrade investments are not recovered ■ Cheaper to extend lifetime than built a new one
■ Regarding facilities commissioned since 1998 ✓ Methodology results in over-recovery of standard gross value ✓ Absent of tenders for new facilities	→	■ Investment recovery depends on rate of return required for your capital ■ CNE is requiring a low rate of return, regardless actual capital costs
■ Reduction of incomes from other non-electrical activities	→	■ A wide range of reasons (economical, legal, etc) reject the claim

22

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Developing Revenue Requirement

Controversial items of the methodology

REE claims	*CNE opinion*
■ "Old fashion" standard costs due to: ■ Environmental, bureaucracy, social acceptance, and ground costs increase ■ Insufficient standard for short lines ■ Increase of maintenance costs ■ Unconsidered costs in current standard ■ Maintenance of transformers ■ Investment in reactive control ■ 4 circuits and underground lines ■ Recovery of deviations	➡ *Overall agreement but it is necessary to modify the methodology so that its claims are also considered*

CNE focused on consumer whereas transmission companies focused on shareholders

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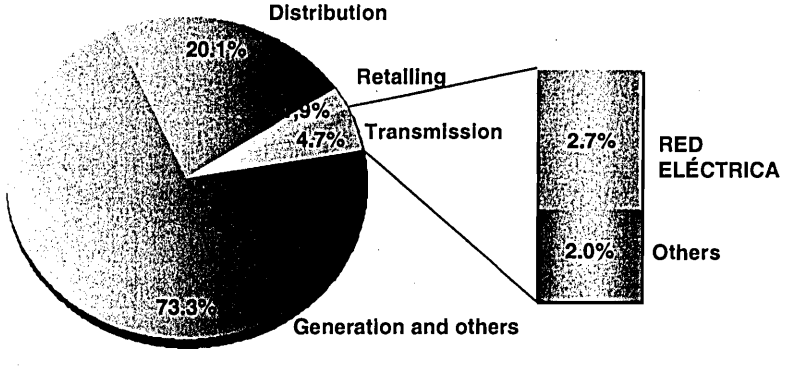
Developing Revenue Requirement

Distribution of Spanish Electricity Sector revenues

Year 2002

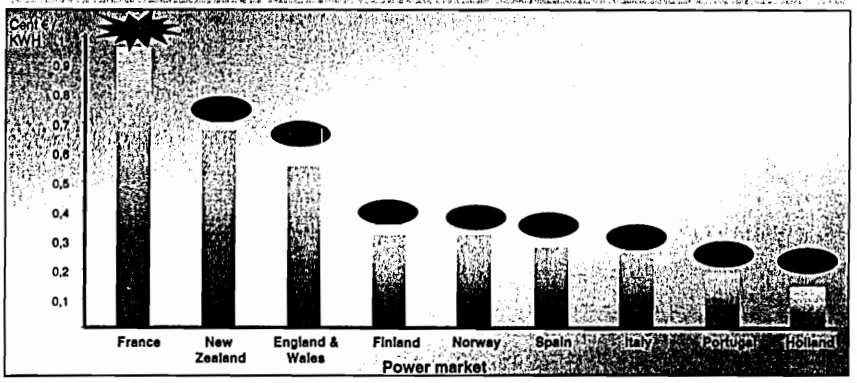
Total =13,457.40 M€ Transmission = 633.26 M€



Western European Case Study: Spain

Benchmarking on Transmission charges

Transmission cost per kWh



In Spain, the weight of transmission over the average price of electricity supply is relatively low

Source: Andersen 2002

Summary

- Regulatory framework of Transmission in Spain
- Developing Revenue Requirement
- Reporting to the Regulatory Authority
- Network charges in Spain

Appendix: Standard costs for transmission facilities

Regulatory bodies in Spain

- The State General Administration
  - ✓ Currently the Ministry of Economics
  - ✓ Main and final regulator
  - ✓ Much power but few resources
- The Spanish National Energy Commission (CNE)
  - ✓ Advisory body for the State General Administration
  - ✓ Few executive functions
  - ✓ Low power but lots of resources
- The Autonomous Regions or Communities (ACs)
  - ✓ Some fuctions related to authorisations and access and connection to the grid in their territories

Regulation on reporting: Rules vs Reality

What Regulation says	*What it is really done*
■ Each 1 December of year n, companies must communicate technical and economical data on facilities commissioned and closed down along last 12 months	■ Each 1 December of year n, companies must communicate technical and economical data on facilities commissioned and closed down during year n (including forecast until 31 December)
■ Ministry calculates the revenue requirement	■ CNE calculates the revenue requirement and communicates Ministry and Companies calculates it in parallel and send to the Ministry
■ National Energy Commission issues a report (not binding)	■ National Energy Commission issues a report (not binding)
■ Ministry approves through a legal provision	■ Ministry approves through a legal provision
■ External audit on the former facilities before 1 December of year n+1	■ External audit on the former facilities before 1 December of year n+1
■ Ministry may correct revenue requirement according to external audit information	■ Ministry may correct revenue requirement according to external audit information

Much simpler mechanism than in other liberalised markets

Usual points of disagreement between CNE and REE

- Permanent controversial items of the methodology
  - ✓ CNE claims about revision of the methodology
  - ✓ RED ELÉCTRICA claims on the same issue

Since the current methodology is in force, yearly CNE reports insists in its claims

- Revision of parameters (every 4 years)
  - ✓ Rate of return, X and Y are revised each 4 years
  - ✓ Revised according to Ministry criteria
- Prevision of new facilities commissioned (every year)

Consequences of such scheme

- Disagreement between CNE and companies calculations:
  - ✓ CNE focused on reducing electric system costs
  - ✓ Companies focused on maximize revenues
- CNE's opinion must be considered by Ministry but IS NOT BINDING:
  - ✓ Ministry pays less attention to transmission costs due to its low weight on the electricity tariff
  - ✓ Companies try to "capture" the Ministry
- Ministry in the middle of two different positions:
  - ✓ Normally applies "literally" the methodology
  - ✓ Does not pay attention to proposals about methodology revision, unless CNE and companies agree them

RED ELÉCTRICA internacional

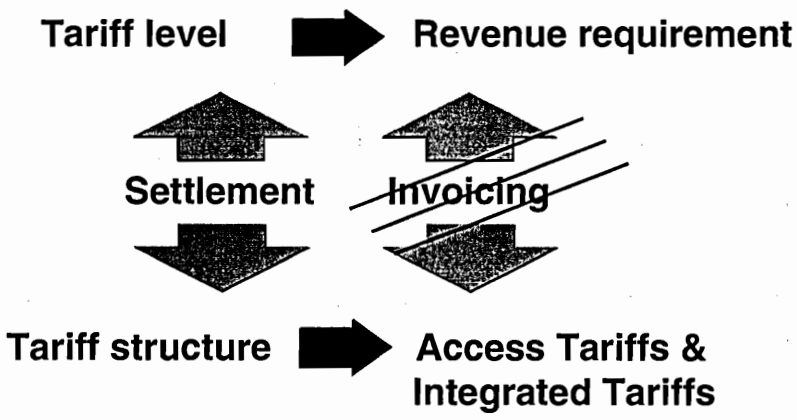
Summary

- Regulatory framework of Transmission in Spain
- Developing Revenue Requirement
- Reporting to the Regulatory Authority
- Network charges in Spain

Appendix: ***Standard costs for transmission facilities***

RED ELÉCTRICA internacional

Recovery of transmission costs



Recovery of approved transmission revenue requirement is guaranteed through the settlement procedure carried out by the CNE, no matter the actual incomes obtained from invoicing integrated tariffs and access tariffs

Overall principles of network charges

- Two ways of charging network costs
  - ✓ Implicit inclusion in integrated tariff paid by franchised customers
  - ✓ Access Tariffs paid by qualified consumers
- Bundle Access Tariffs:
  - ✓ Cover other costs aside Network costs
  - ✓ Tariff structure fixed but no objective methodology to allocate prices to each group of customers that tariff structure consists of

CNE proposal on prices allocation not yet implemented

Access Tariffs regulation (1)

Costs covered by Access Tariffs

- Covered
  - Transmission and distribution
  - Permanent costs of the system
    - Transition to competition costs (stranded costs)
    - Remuneration of SO, Market Operator and National Energy Commission (advisory regulator)
  - Costs of supply diversification and security
- Not included
  - Constraints costs
  - Ancillary services

Access Tariffs regulation (2)

- Who invoices: Distribution companies
- Who pays: Qualified consumers and exports
- Type of pricing: Tariffs differentiated by connection voltage and seasonal time-of-day period, but no geographical factor considered
- Terms: Two terms:
  - Power related
  - Energy related

Access Tariffs regulation (3)

Structure currently in force

- Low voltage tariffs
  - ✓ Tariff 2.0A:
    - ◆ Simple, without differentiation of periods
    - ◆ Contracted power not higher than 15 kW
  - ✓ Tariff 3.0A:
    - ◆ General tariff with 3 periods
    - ◆ Available for any supply in low voltage
- High voltage tariffs:
  - ✓ Tariff 3.1A:
    - ◆ Specific for voltages between1 and 36 kV with 3 periods
  - ✓ Tariff 6:
    - ◆ General tariff for high voltage.
    - ◆ 5 five voltage levels (1 for interconnectors)
    - ◆ 6 periods for each voltage level

RED ELÉCTRICA internacional

Summary

- Regulatory framework of Transmission in Spain
- Developing Revenue Requirement
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Appendix: Standard costs for transmission facilities

RED ELÉCTRICA internacional

Unit standard costs to determine VAI

- Overhead lines (unit : MPTA/km)

Nº circuits/voltage	400 kV	220 kV
1 circuit	24,83	14,71
2 circuits	39,81	23,52
More than 2 circuits	49,27	29,03

These costs are adjusted by four factors dependant upon:

- transmission capacity of the line
- whether or not the line is designed for twin circuits
- whether the circuit is the second have been laid on a line designed for twin circuits
- lines less than 15 km

Unit standard costs to determine VAI

- Underground lines (unit : MPTA/km).

Nª circuits	220 kV
1 circuit	390,22
2 circuits	663,37

Underground lines in a voltage of 400 kV are considered as special facilities

- Busbars (unit : MPTA/bay).

Type/voltage	400 kV	220 kV
Conventional	270,66	132,70
Shielded	338,98	229,92

Unit standard costs to determine VAI

- Transformers (unit : MPTA/MVA).

Secondary voltage	Primary voltage 400 kV	Primary voltage 220 kV
400	1,24	
220	1,24	1,24
131/110	1,42	1,98
66		2,82
50/45		3,30
<36		4,17

- Reactors: 1,24 MPTA/MVAr.

Unit standard costs to determine CET

- Operation and maintenance unit standard costs

Líneas	PTA/ km circuito	PTA/ posición
220 kV	298.264	7.047.037
400 kV	516.533	13.269.570

RED ELÉCTRICA internacional

12

Majda PARIPOVIĆ and Bojan KUZMIČ
Energy Agency of the Republic of Slovenia

ELECTRICITY NETWORK PRICING IN SLOVENIA

WORKSHOP: DEVELOPING UNBUNDLED TRANSMISSION TARIFFS

Zagreb, 28 th May 2003

Content (1)

- The liberalised market and the organisation of the Slovenian electricity power sector
- Structure of the network price
- Transmission and distribution charges
- Purpose of economic regulation
- Examining and verifying revenue requirements
- Volume forecast of consumption
- Factor X and smoothed revenue
- Corrective factors

- Network charges in the first regulatory period

The liberalised market and the organisation of the Slovenian electricity power sector

The process of Slovenia's accession to the EU:

1997	Negotiations for EU membership started
1999	New Energy Act introduced the energy market
December 2002	Negotiations successfully concluded
1st May 2004	**Slovenia will become an EU member**

The liberalised market and the organisation of the Slovenian electricity power sector

LEGAL FRAMEWORK

Energy Act, October 1999
(Official Gazette of the Republic of Slovenia, No. 79/99, 8/00)

- Harmonised national legislation with that of the EU (Directive 96/92/EC).
- Main features:
  - Public service obligations
  - Eligibility status and market opening
  - Access to networks
  - Unbundling
  - Licencing
  - Regulator

The liberalised market and the organisation of the Slovenian electricity power sector

Access to networks

- Regulated third party access (rTPA) - transmission and distribution networks
- Networks charges are set by the Regulator
- Eligibility status and open access to networks – costumers with a connection exceeding 41 kW in capacity and electricity distribution service providers

15th April 2001 – opening electricity market internally

1st January 2003 - opening electricity market externally

The liberalised market and the organisation of the Slovenian electricity power sector

Unbundling

Separate accounts for each energy activity

- The same legal entity allowed to perform several public service obligations
- However, a legal entity performing
  - several energy activities, or
  - another activity in addition to one energy activity

The companies must keep separate accounts, ensure their audits and has to publish the audited accounts in a daily newspaper.

The liberalised market and the organisation of the Slovenian electricity power sector

Licencing

- In order to perform 21 different energy related activities
- 5 conditions for obtaining a licence – more formal than substantial
- Licence is granted (refused, revoked) by the Energy Agency

Licence = administrative decision

Energy agency has until now granted near 800 licences.
A list of all licenceholders performing energy activities is available: www.agen-rs.si

The liberalised market and the organisation of the Slovenian electricity power sector

REGULATOR – ENERGY AGENCY

Established by Energy Act and Government Decision on the Foundation of the Energy Agency (year 2000)

Legal entity under public law

Independent organisation:

- Main financing through a levy on electricity use-of-networks charges, only minor part through state budget (in 2003 less than 1%)
- Term in office of the director (nominated by the government - for 5 years)
- Formally independent from the ministry

The liberalised market and the organisation of the Slovenian electricity power sector

ENERGY AGENCY

Main responsibilities – market monitoring

- Price control of regulated services
- Disputes
- Licences
- Other related tasks

Data collection: obligation for all market participants to provide the Energy Agency with all the information required for the implementation of its tasks.

At the moment 22 employees.

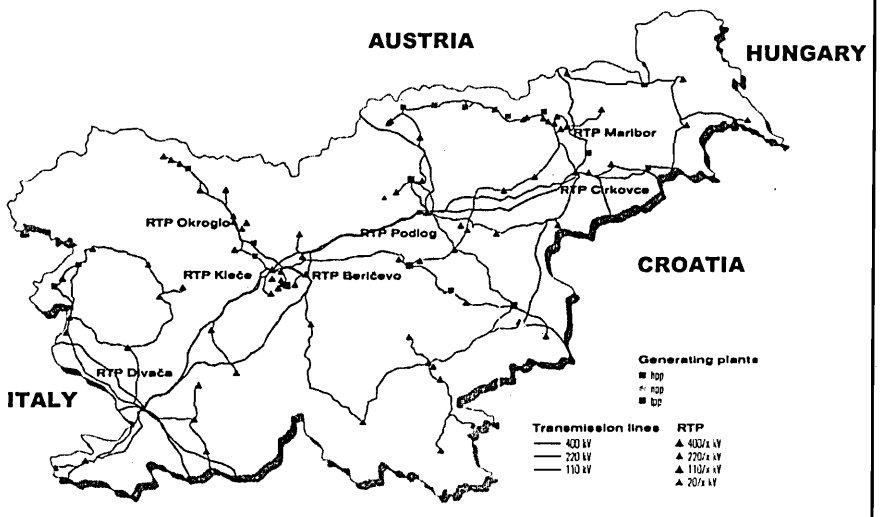
The liberalised market and the organisation of the Slovenian electricity power sector

SLOVENIAN ELECTRICITY POWER SYSTEM

• Population:	2 million
• Country area:	20,256 km^2
• Total installed capacity:	2,700 MW
• Total consumption 2002:	11.5 TWh
• Total production 2002:	13 TWh
• Transmission network:	2,549 km of lines
• Interconnections :	Italy, Austria, Croatia
• 5 Distribution networks/operators	
• Total number of customers:	800,000
• Number of eligible customers:	6,000

The liberalised market and the organisation of the Slovenian electricity power sector

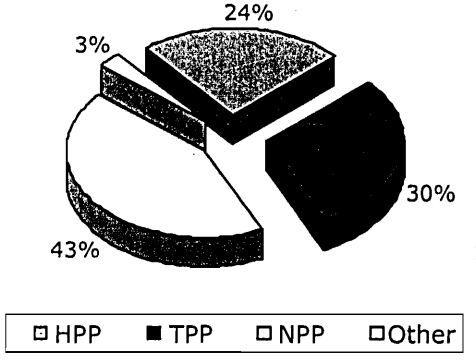
SLOVENIAN ELECTRICITY POWER SYSTEM



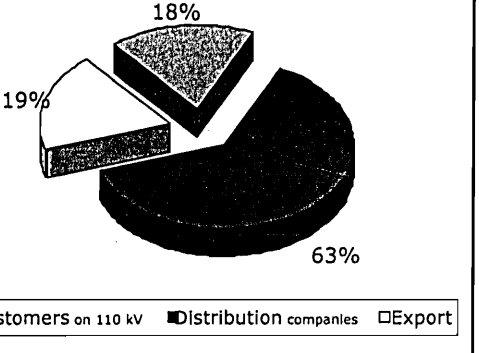
Slovenian electricity system - transmission lines, substations (RTP) and generating plants

The liberalised market and the organisation of the Slovenian electricity power sector

Production in 2002



Consumption in 2002



The liberalised market and the organisation of the Slovenian electricity power sector

SLOVENIAN ELECTRICITY POWER SYSTEM

- Small in comparison with neighbouring systems
- Important transit route
- The bulk of production is located in the east of the country (85%) while electricity consumption is fairly evenly distributed countrywide
- Networks are old and in need of high investments
- The 400 kV network is not looped inside the country, which precludes major transits

The liberalised market and the organisation of the Slovenian electricity power sector

MARKET PARTICIPANTS:

- **Suppliers**
- **Market operator**
- **Transmission**
- **Distribution**

The liberalised market and the organisation of the Slovenian electricity power sector

MARKET PARTICIPANTS:

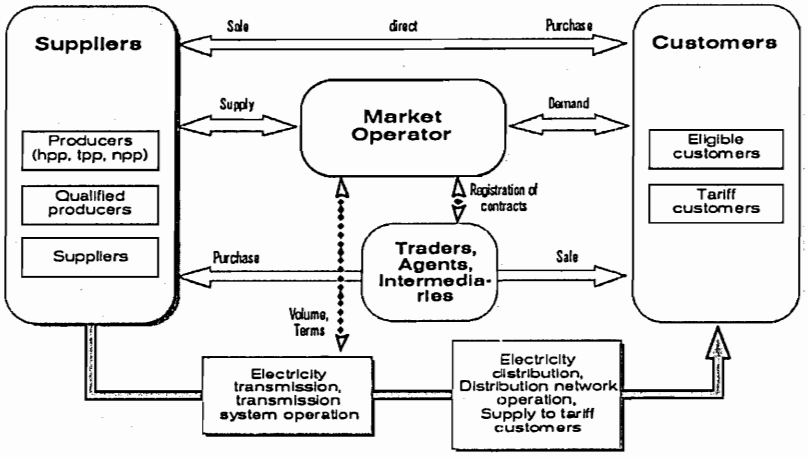


Chart of the electricity market

The liberalised market and the organisation of the Slovenian electricity power sector

SUPPLIERS

Electricity producers in Slovenia

In 2001 five producers and a coal mine were merged into Holding HSE.

Following this merger, producers on the electricity market include:

1. Holding of Slovene power plants – HSE

and three independent enterprises:

1. Nuclear power plant at Krško (NPP)
2. The combined heating & power plant at Ljubljana (CHP)
3. The coal-fired thermal power plant at Trbovlje (TPP)

The liberalised market and the organisation of the Slovenian electricity power sector

MARKET OPERATOR

Borzen – founded 2001, daughter company of Eles (TSO)
www.borzen.com

- Public service obligation
- Principal tasks:
  - To provide an interface for purchase and sale offers – an exchange (daily, hourly markets)
  - To account and settle transactions concluded on the market clearing house
  - The record - keeping (registration) of bilateral contracts
  - Design of operation schedules
  - Publication of market price trends

The liberalised market and the organisation of the Slovenian electricity power sector

TRANSMISSION

Eles **www.eles.si**
100% State owned

- Until 15th July 2001 single buyer & seller of electric power in the transmission system
- 2 public service obligations - regulated:
  1. Transmission system operator (TSO)
  2. Electricity transmission
- Market activities:
  1. Telecommunication and
  2. "ICES" Training Centre

The liberalised market and the organisation of the Slovenian electricity power sector

Eles - TSO

The transmission system operator may no longer trade electricity.

General enactments:

- Draft Transmission network code
- Transparent and non-discriminatory Criteria for Network Access (Energy Agency assent)
- Operation of the Balancing Market

Contracts:

- Contract for Access to network
- Contract on Balance deviation
- Contract on Electricity Purchases from Qualified Producers

Eles & Cross border trading

The liberalised market and the organisation of the Slovenian electricity power sector

DISTRIBUTION – 5 companies

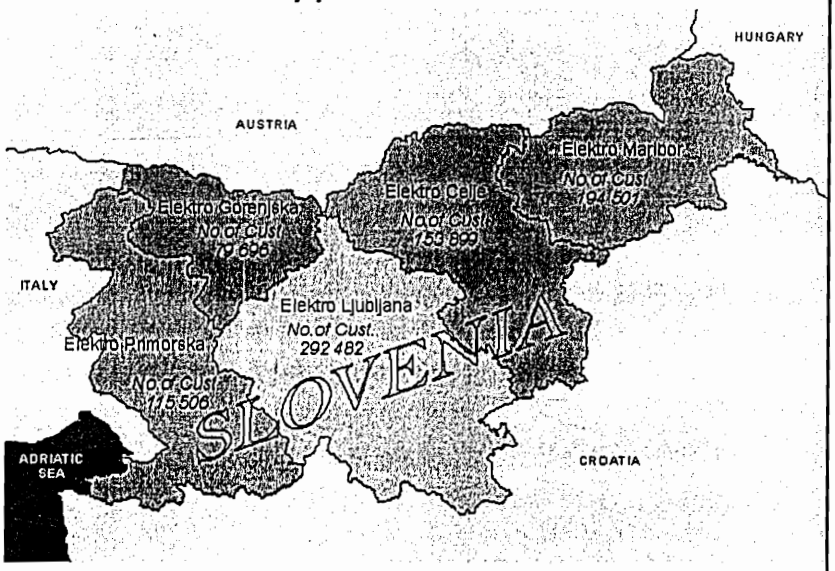
Ownership:

- The principal stakeholder is the State (approximately 80%)
- Various Authorised Investment Companies hold the remainder of equity

Distribution companies

separated their energy activities, obtained licences for them and modified their organisational structure in compliance with the new regulations

The liberalised market and the organisation of the Slovenian electricity power sector



Structure of the network price

Network use charge components:

- Portion for the transmission system charge
- Portion for the distribution network charge
- Portion for ancillary services
- Portion for the work of the Energy Agency
- Supplement for priority dispatching
- Supplement for registration of contracts on the organised electricity market

The Energy Agency is responsible for defining:

- The portion for the transmission system charge
- The portion for the distribution network charge
- The portion for ancillary services

Other portions and supplements are under the competence of the government.

BEST AVAILABLE COPY

Transmission and distribution charges

Transmissions and distribution charges cover:

- operation and maintenance costs
- costs for development of the network
- costs of network losses

that the regulated businesses have by executing their public service obligations.

Purpose of economic regulation

- caused by the need to monitor and control the activities of companies in markets where full and fair competition cannot be relied upon to protect customers or other interests

- the regulated network businesses have an exclusive monopoly granted by the Slovenian Energy Law and other ordinances

- the Energy Agency should protect customers by acting as a proxy for normal competitive forces

- a good regulatory regime should provide companies with similar opportunities and incentives to those they would face in a competitive market

Purpose of economic regulation

- the Energy Agency prepared in the middle of the year 2002 a consultation document
- has formulated a set of consultative queries associated with the major decisions to be made for the introduction of an effective and workable network price control
- decided to adopt a light-handed approach for network price control
- the Energy Agency adopted the price cap regulation for the electricity networks and criteria of assessment of justified costs for the first regulatory period 2003-2005.

Methodology of economic regulation

- price cap regulation avoids the need to reset annually the regulated rates
- provides stronger price stability and predictability
- the Energy Agency considered that the level of price caps is sufficient to cover the efficient operation and maintenance costs and an adequate return on existing capital and new investments
- the limit on allowed price increases is expressed in terms of a ratio of required revenues. This cap is in turn determined on the basis of a CPI-X formula as presented below:

$$(1 + CPI - X) \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t+1} q_{ij}^{N}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t} q_{ij}^{O}}$$

Methodology of economic regulation

where there are *n* tariff categories, which each has up to *m* components, and where:

p^t_{ij} is the price being charged in year t for component *j* of tariff *i*;

p^{t+1}_{ij} is the proposed price for component *j* of tariff *i* in the coming year t+1;

q^n_{ij} and q^o_{ij} are the forecasted or historic quantities of component *j* of tariff *i* that will be used in the price control (N indicates that quantities apply for the coming year and O that quantities apply for the previous year);

CPI is the historic annual percentage change in the Consumer Price Index in Slovenia. For the first regulatory period CPI was replaced with PPI = the historic Producer Price Index

X is a percentage figure determined by the Energy Agency and reflects generally the productivity improvement target (additionally X enables smoothing of target revenue requirements)

Examining and evaluating revenue requirements

The Energy Agency evaluated the required revenue by taking into consideration:

- justified operational and maintenance (O&M) costs,
- depreciation,
- justified costs of network losses,
- return on assets

A part of the above costs is covered by revenues from other activities of regulated businesses and are not related to network charges.

Examining and evaluating revenue requirements

REQUIRED DATA

- unbundling ensured since 1.1.2001

The Energy Agency required:

- audited unbundled reports (profit and loss account, balance sheet...) already for the year 2001 and for the first half of the year 2002,
- data for the regulatory asset base (RAB),
- companies evaluation of the costs of regulated businesses,
- evaluation of non-controllable costs,
- the volume forecasts upon all customer classes and seasons,

Examining and evaluating revenue requirements

OPEX

- 'cleaned' data of operation and maintenance costs (O&M) from the profit and loss accounts were used as an input for benchmarking
- an OPEX benchmarking study over several comparable efficient companies from abroad had been elaborated to establish the efficiency of each company
- in the first regulatory period 80 % of the efficiency of the most efficient comparable business was claimed
- the productivity improvements were defined from 4 to 9 % yearly
- the amount of non-controllable costs was added to the amount of controllable costs.

Examining and evaluating revenue requirements

DEPRECIATION

- for the existing assets the book value and the straight-line depreciation were used
- for new assets 5 % yearly depreciation or 20-year average assets life
- a revaluation of all fixed assets by the end of 2001
- the results of the revaluation had a great influence both on the depreciation and on the opening regulatory asset base value

Examining and evaluating revenue requirements

COSTS OF NETWORK LOSES

These costs were evaluated at an average price of 8 SIT/kWh.

RETURN ON ASSETS

Was evaluated on the basis of the average regulatory asset base (RAB), considering 5.1 % pre tax WACC.

WACC = Weighted Average Cost of Capital

Examining and evaluating revenue requirements

REGULATORY ASSET BASE (RAB):

- opening net present value of fixed assets per 1.1.2003
- + capital expenditure (new investments)
- - capital contributions
- - depreciation
- = closing value of regulatory assets = opening value of the second year of regulatory period

• the investments cost were evaluated on the basis of investment plans at current prices

• the working capital was not included in the RAB

The average regulatory asset base is calculated considering opening and closing value.

Examining and evaluating revenue requirements

The cost of capital = the estimated rate of return

WACC should be calculated on the basis of an efficient standard equity/debt ratio.

• the utilities in Slovenia are operating with low debt / equity ratio (high equity share).

• for the first regulatory period an average real interest rate of 4.5 % was considered for the calculation of costs of debt.

• for the purposes of quantification of the rate of return on equity the CAPM (Capital Assets Pricing Model) was used. The evaluation of the real risk free rate for equity amounted to 11.8 %.

Examining and evaluating revenue requirements

- intermediate measures were necessary
- the Energy Agency decided to equalize the cost of debt and the cost of equity in the first regulatory period.

REQUIRED REVENUE

- the required revenue of each regulated business was evaluated
- the required revenue was reduced for the evaluated amount of revenue from other activities

Volume forecast of consumption

- the regulated companies had prepared volume forecasts of consumption
- these forecasts were checked and revised by the Energy Agency

The anticipated growth of the consumption is:

	2003	2004	2005
contracted power (kW)	0,7%	1,0%	1,0%
energy (kWh)	3,0%	2,3%	1,6%

- a rise of 38.17 % for the transmission and distribution charges would be needed
- upwards price adjustment was necessary to achieve the efficient cost reflective level

Factor X and smoothed revenue

Factor *X*
has a dual function:

- takes into account productivity improvement (cost reductions)
- revenue smoothing within the regulatory period

The first function results from the efficiency scores (benchmarking) and the required degree of efficiency convergence speed.

The second (smoothing) function is based on procedure that generates prospective revenues for each year of the regulatory period providing an expected return commensurate with the business risk involved.

The X is calculated so that the net present value of the smoothed revenue streams is exactly the same as the target revenues.

Factor X and smoothed revenue

Factor X for transmission and distribution charges is – 15.03 %.

For the particular regulated companies factor X ranges from –11 % to -18 %.

Considering the CPI-X formula a yearly rise of 15.03 % for transmission and distribution charges is needed.

In 2003 the smoothed revenue attains only 84 % of the required revenue.

Corrective factors

are used as a compensation mechanism between the revenue from network charges and the smoothed revenue of individual regulated businesses.

They are necessary due to:

- unique network charges on the whole territory of Slovenia,
- different smoothed revenues as a consequence of different costs for assuring public services of distribution

Smoothing is performed by taking into consideration the corrective factors for the portion of transmission charges and is stipulated in the contracts on access to transmission network.

Content (2)

Network charges in the first regulatory period

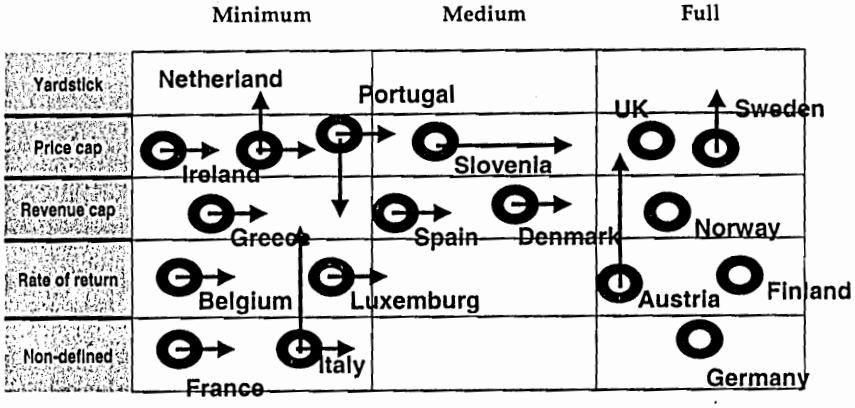
Network charges in the first regulatory period

Timetable for setting NC in Slovenia

	Projects	2000				2001				2002				2003			
							internal market opening							external market opening			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
	Definng Method for cost allocation																
	Definng Prices for Network Charges for 2001																
	Definng Prices for Network Charges for 2002																
Preparing for Regulatory period 2003-2005	Consultation Paper																
	Benchmarking of Transm. and Distrib. Tariff and costs (OPEX)																
	OPEX and CAPEX analyses for unbundled companies																
	Defing Prices for Network Charges for 2003																
	Defing Prices for Network Charges for CBT (ETSO aggrement)																

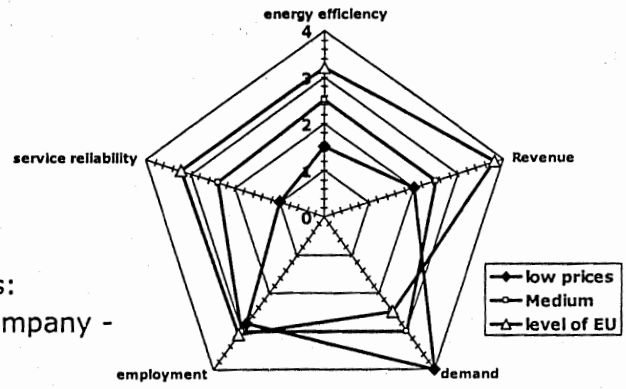
Network charges in the first regulatory period

Declared market opening in EU Member States and Type of regulation



Network charges in the first regulatory period

Differential interest



Interest holders:

- Regulated company - owner
- customers
- State – energy policy

Network charges in the first regulatory period

Structure of Network Charges

- Voltage level
  - HV- 400, 220, 110 kV
  - MV - 35, 20,10 kV
  - LV – 0,4 kV
- Customer Group
  - Criteria: equivalent full load operating hours
- Tariff Component
  - Accounting power
  - Supplied energy
- Seasonal, time-of-day differential

Network charges in the first regulatory period

Method for Cost Allocation

Input:

CAPEX:
- *network*
- *Substation / transformer*
- *Other*

Demand in previous year
- *Max. xx kW/month*
- *xx kWh/a*
- *Per customer group*

Calculation

Distribution of income on voltage level:
- Annual cost (CAPEX+OPEX)
- group of customers (type of consumption):
  1. *Household*
  2. *Consumer with equivalent full load operating hours T<2500 h*
  3. *Consumer with equivalent full load operating hours T>2500 h*
  4. *Consumer with equivalent full load operating hours T>6000 h*

Criteria:
1. *Post stamp*
2. *Gross method*

Output:

Network Charges:
- Voltage level
- Customer group
- Tariff component
  - *Tariff for accounting power*
  - *Tariff for supplied energy*

Network charges in the first regulatory period

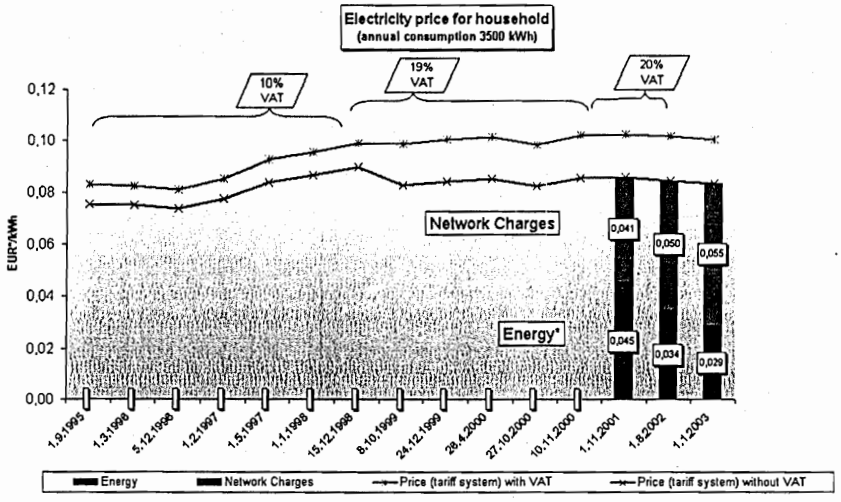
Table 7 Price list for eligible and tariff customers for 2003

				Active power consumption SIT/kWh			
Voltage level		Season	Billing capacity SIT/kW/month	PT	HT	LT	Single tariff metering
HV	T ≥ 6000 h	HS	450,76	0,769	0,769	0,730	
		MS	379,90	0,735	0,735	0,704	
		LS	332,66	0,712	0,712	0,686	
	6000 > T ≥ 2500 h	HS	426,36	1,053	1,053	0,948	
		MS	360,38	0,962	0,962	0,878	
		LS	316,39	0,901	0,901	0,831	
	T < 2500 h	HS	183,12	2,295	2,295	1,903	
		MS	165,78	1,955	1,955	1,642	
		LS	154,23	1,729	1,729	1,468	
MV	T ≥ 2500 h	HS	869,20	1,862	1,862	1,570	
		MS	758,81	1,680	1,680	1,430	
		LS	648,42	1,501	1,501	1,292	
	T < 2500 h	HS	246,81	5,421	5,421	4,308	
		MS	225,32	4,732	4,732	3,778	
		LS	203,85	4,043	4,043	3,248	
LV	T ≥ 2500 h	HS	1578,42		3,508	2,837	
		LS	1236,43		2,837	2,320	
	T < 2500 h	HS	468,17		9,386	7,358	
		LS	382,39		7,358	5,798	
	Without power registra.	HS	248,01		12,511	9,762	11,136
		LS	191,18		8,043	6,325	7,184
	Tariff customers		191,18		8,043	6,325	7,184
	Public lighting						9,640

PT – peak tariff
HT – high tariff
LT - low tariff

HS – high season
MS – medium season
LS – low season

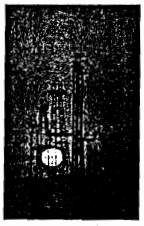
Network charges in the first regulatory period



Network charges in the first regulatory period

Ancillary Services

- Primary and secondary regulation
- Tertiary regulation
- System losses – part of Network Charges
- Black Start



- **Quantity of Ancillary services are set on UCTE rules**
- **Possibility for Tertiary regulation – lease also by customers**
- **Market for ancillary services in Slovenia**

Network charges in the first regulatory period

Eles & Cross border trading

- Member of the UCTE and ETSO
- Eles determines the capacity (in co-operation with neighbouring TSO)
- Allocation:
  Capacity divided 50% - 50% with neighbouring TSO
  Capacities in 2003 are allocated by 3 principles:
  - Pro rata
  - Auction (organised by Borzen)
  - First come first served

- **1st January 2003 – ETSO-CBT full membership**

This will allow the players on the Slovenian market equal terms with others engaged in cross-border trading in EU.

Network charges in the first regulatory period

Florence Forum

"Establishment of temporary CBT mechanism"

1.step – 1.3.2002 – 31.12.2002

EXPORT FEE – **1** EUR/MWH

INJECTION FEE (FROM PERIMETER COUNTRY) - 1 EUR/MWH

IMPORT* and TRANSIT* = 0 EUR/MWH

2. step – 1.1.2003 – 31.12.2003

EXPORT FEE – **0,5** EUR/MWH

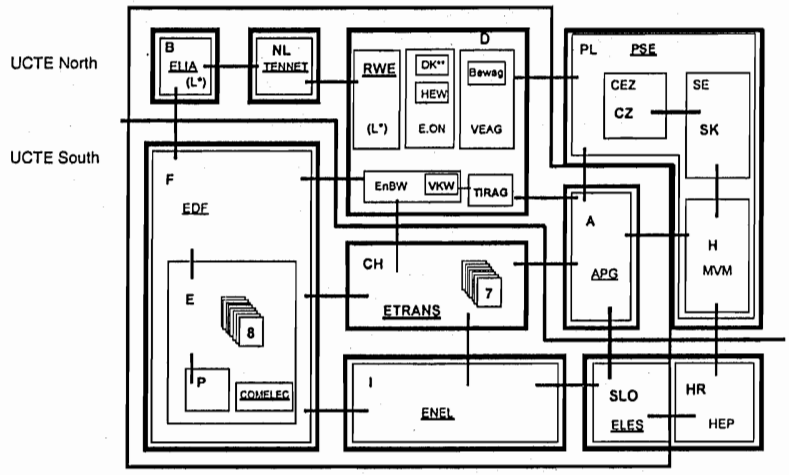
INJECTION FEE (FROM PERIMETER COUNTRY) - 1 EUR/MWH

IMPORT* and TRANSIT* = 0 EUR/MWH

* - Between members countries

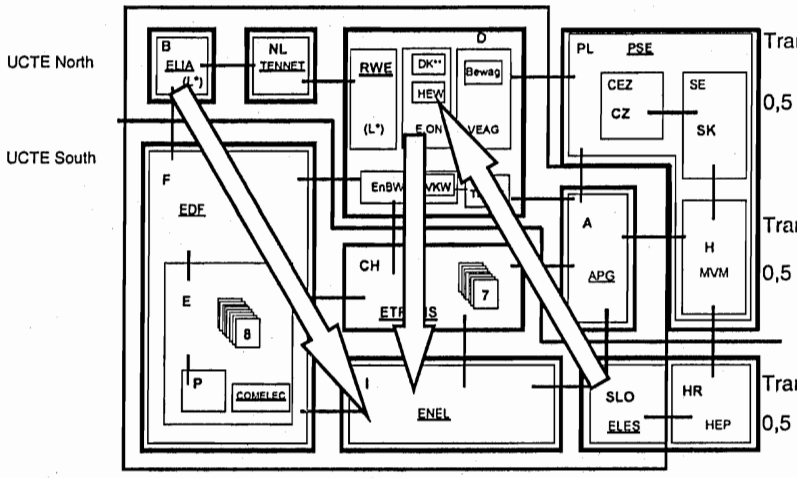
Network charges in the first regulatory period

ETSO Member in 2003 (1)



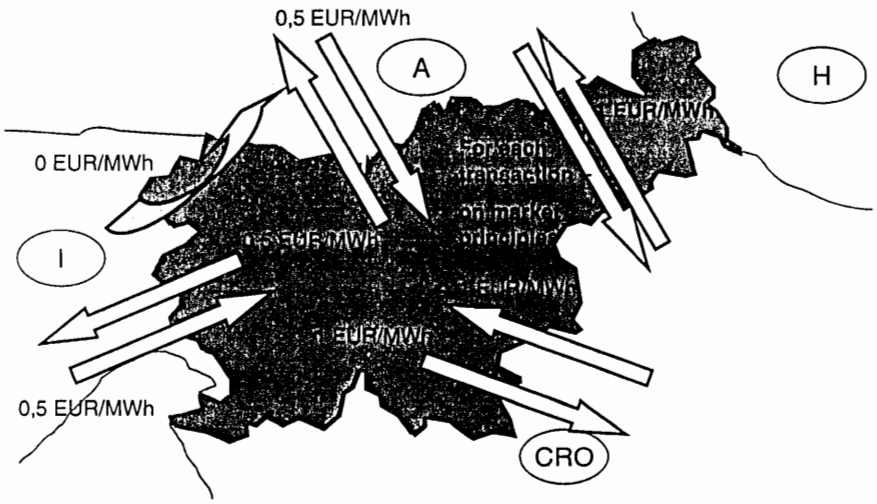
Network charges in the first regulatory period

ETSO Member in 2003 (2)



Network charges in the first regulatory period

Slovenian CBT under ETSO mechanism in 2003



Thank you for your attention

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13

Essential Conditions for a Network Tariff

Charles F. Zimmermann, Nexant Inc.

Southeast Europe Regional Workshop on Developing Unbundled Transmission Tariffs

Sponsored by
U.S. Agency for International Development
Ministry of Economy of Croatia
Hrvatska Elektroprivreda
U.S. Energy Association

Zagreb, Croatia, May 27-29, 2003

Introduction

- **What is a "network tariff?"**
  - the fees for the use of the network, including energy-related fees, capacity-related fees, and fixed fees designed to cover metering and billing expenses
- **Which costs are excluded from the network tariff?**
  - the cost of connecting new producers of electricity
  - the cost of balance power
  - ancillary services (in some countries, e.g. Croatia)
  - the cost of operating an energy exchange
  - generating costs that are recovered via (a) bilateral agreements or (b) energy sales at a power exchange
  - costs related to sales and marketing

Is it a "network tariff" or "network fee?"

- The European Commission refers to published tariffs. This phrase is correct, at the international level
  - A tariff is a "schedule of prices or fees" (in English)
- Some national energy laws cite use of network fees. This phrase is correct, at the national level
  - In Croatia only captive customers pay a "tariff." There will be transmission and distribution network fees
- Transit is one category of service. The cost of transit service should be covered by a published tariff or a CBT mechanism. Negotiated access is not the best option
  - Ideally, all transit tariffs should be agreed at the international level, but that may not always be possible

Network tariffs in South East Europe

- Two documents may be used as a basis for designing network tariffs in South East Europe:
  - the new (2003) EU Electricity Directive
  - the Athens Memorandum, signed 15.11.2002
- Target: TPA for all non-household customers by 2005
- Both transmission and distribution are covered
  - There is no standard rule on how to separate transmission assets from distribution assets
  - In this workshop we will discuss transmission only

2003 EU Electricity Directive: TPA based on published tariffs

- **Article 20 - Third Party Access**
  - Member states shall ensure the implementation of a system of third party access to the transmission and distribution systems based on published tariffs, applicable to all eligible customers and applied objectively and without discrimination between system users...
- **Article 23 - Regulatory Authorities**
  - The regulatory authorities shall be responsible for fixing or approving, prior to their entry into force, at least the methodologies used to calculate or establish the terms and conditions for:
    - (a) connection and access to national networks, including transmission and distribution tariffs;
    - (b) the provision of balancing services.

Athens Memorandum: Regulated TPA based on published tariffs

1. **Functioning of the Market**

   The adhering parties agree, in order to promote the functioning of effective markets:

   1. **To implement a system of Regulated Third Party Access to the transmission and distribution systems based on published tariffs, applicable to all eligible customers and applied objectively and without discrimination between system users.**
      1. The countries shall ensure that these tariffs, or the methodologies underlying their calculation, are approved prior to their entry into force by the national regulatory authority and that these tariffs are published prior to their entry into force

Services covered by a transmission tariff

- **Access to overhead lines at 400, 220, 110 kV**
- **Access to transformer substations 400/x, 220/x**
- **Access to substations 110/x kV**
  - In Croatia some of these substations are owned by the distribution network. Some are jointly owned by transmission and distribution
- **Access to interconnectors**
  - In theory a national transmission company might invest in various interconnections needed to supply that country
  - **In most European countries, transmission network energy losses are covered by the transmission tariff**
  - **Metering and billing services at 400, 220, 110 kV are included in the transmission tariff - not suppliers' fees**

What is included in the cost of service?

- **A transmission company is a service provider**
  - **The customer pays for the services he receives**
  - **Cost of service =**
    operating cost + depreciation + interest on loans + some type of allowance for capital investment
- **The allowance for capital investment depends on the way capital expenditures are financed**
- **For example:**
  - **Cost of service =**
    operating cost + depreciation + interest on loans + profit allowance

Essential conditions for a transmission tariff

- ⌘ **Transactions covered by the tariff must be identified**
- ⌘ **Power flows should be metered**
- ⌘ **Total revenue should include transit revenue**
- ⌘ **Accounts receivable and accounts payable should be kept within reasonable limits**
- ⌘ **Cross-subsidies should not be allowed**
- ⌘ **Inter-TSO compensation should be anticipated**
- ⌘ **Separate financial accounts should be prepared**

Transactions covered by the tariff must be identified

- ⌘ **Scheduled transit flow - usually covered (until there is a CBT mechanism)**
  - ☒Although electricity does not follow contract paths, it may be possible to allocate transit flows to importing countries and ask the importers to pay for use of the transmission network
  - ☒The best solution is a CBT mechanism. Next best would be an agreement on the "importer pays principle" plus a recognition that transit tariffs without CBT are only temporary
- ⌘ **Pumped storage hydro - usually not covered**
  - ☒Some hydro stations consume energy when water is pumped into the reservoir. When electric energy is transmitted from thermal stations to hydro stations, who pays for transmission service? Who pays for electric energy losses?

Transactions covered by the tariff must be identified

- **Loop flows - not covered**
  - Loop flows are unscheduled transit flows. Without a CBT mechanism it is nearly impossible to collect payment for loop flow
- **Small power production sold to retail suppliers - usually not covered**
  - Although there are no valves controlling energy flow between the transmission network and distribution network, energy from small power production flows in medium- and low-voltage networks
  - What do suppliers buy when the wind is not blowing, or the river flow is minimal, and the small power generator is not working?
  - Through capacity payments, the supplier should pay for his use of the transmission network during the system peak hour

Power flows should be metered

- **Metering of power flows is needed -**
  - **between the transmission network and neighboring transmission networks (400, 220, 110 kV)**
  - **at each generating station on the transmission grid**
  - **on the input side of transformers owned by large customers directly connected to the 110 kV network**
  - **at the point where ownership is separated between the transmission network and the distribution network**
    - For billing purposes the location of the meter depends on who owns the transformer. If the distribution company owns the transformer then the meter is on the input side.
    - To measure energy losses, it may be useful to meter both sides

Total revenue should include transit revenue

- Interconnectors and transmission capacity additions can be designed to provide transit service
- If the TSO is expected to provide transit service, then the TSO has a right to ask for transit-related revenue
  - Conventional approach: a transit fee per kWh which has no relationship to the peak load on the network
  - Better approach: ask the importing country to pay a two-part fee (capacity and energy charges)
  - Best of all: eliminate published transit tariffs and set up a CBT mechanism similar to the ETSO mechanism

Accounts receivable and accounts payable should be kept within reasonable limits

- To ensure that actual revenues and expenses will be close to the numbers used in the tariff calculation, a transmission company should maintain strict control over accounts receivable and accounts payable
  - Distribution companies and retail suppliers must pay for transmission service
  - If accounts receivable are too high, the problem will not be solved by allowing accounts payable to rise
  - Non-payment and theft at 0.4 kV would be a major obstacle to unbundling of the transmission company

Cross-subsidies should not be allowed

- The transmission tariff should be cost-based
  - In theory most costs are capacity-related. Only energy losses and reactive power are energy-related
  - In practice it is necessary to allocate additional costs to energy charges, to match the sales tariff structure and unbundle transmission from other components
- Subsidies for renewable energy generation are OK but they should not be part of the transmission tariff
  - Ideally, all subsidies should be shown as a separate line in the customer's bill

Inter-TSO compensation should be anticipated

- Basic concept of CBT
  - If a country provides transit services to other countries but does not export to "distant" countries, the CBT mechanism will be a source of revenue for the TSO
  - If a country exports to "distant" countries and does not provide transit service to other countries, the CBT mechanism will be an additional expense for the TSO
- TSO financial accounts should show payments into the CBT fund and receipts from the CBT fund
  - For tariff calculation purposes, the simplest forecast is: CBT payments - CBT receipts = 0

Separate financial accounts should be prepared

- **Article 19 of the 2003 Electricity Directive**
  - Electricity undertakings shall, in their internal accounting, keep separate accounts for each of their transmission and distribution activities as they would be required to do if the activities in question were carried out by separate undertakings...
- **Because the transmission tariff should include an allowance for capital investment, accounts are needed**
  - The statement of cash flows will show whether there is enough cash flow to cover the capital expenditure plan

Separate financial accounts should be prepared

- **True "profitability" is revealed by the balance sheet**
  - Net worth = Assets - Liabilities
  - An increase in net worth is an indication of profitable operations. If the change in net worth can be forecast then there is no need to have a "profit component" in the tariff, even if privatization is planned.
- **Banks would like to see a financial forecast in which cash flow is more than enough to cover debt service**
  - Normally a transmission company is state-owned and the banks that lend money to the company have no recourse to the assets

What to do when there are no accounts?

- It is possible to calculate a transmission tariff for a company that has no financial statements
  - Operating costs can be estimated
  - Depreciation can be estimated, if the value of assets is known and the capital expenditure plan is known
- However, the most likely result is a higher tariff
  - Capital expenditures will have to be financed by increasing the tariff, to raise cash flow
    - No one is going to lend money to a company without financial statements.

14

Designing and Calculating a High Voltage Network Tariff

Charles F. Zimmermann, Nexant Inc.

Southeast Europe Regional Workshop on Developing Unbundled Transmission Tariffs

Sponsored by
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Zagreb, Croatia, May 27-29, 2003

Purpose of this presentation

- **To present a simple approach to tariff calculation, designed for transmission companies in South East Europe that are in the process of being formed**
- **To present sample numbers which are close to the initial estimates used by HEP Transmission for 2003**
- **To give a step-by-step introduction to the Excel file that was prepared for this workshop**

Steps in the tariff analysis

- Identification of the assets of the transmission business
- Definition of customer classes, by voltage level
- Identification of services to be provided and standards of service quality
- Selection of a method to value electric energy losses
- Forecast of demand and capital expenditure
- Selection of a 12-month period in which the tariff will be in effect
- Forecast of operation and maintenance expenses
- Setting of financial objectives
- Forecast of the annual revenue requirement
- Design of the tariff
- Calculation of the proposed tariff

Step 1

1. Identification of the assets of the transmission business
   - How to separate "transmission" from "distribution?"
     - Problems are related to 110/x transformer substations
     - Asset ownership is not the key issue. Tariff calculation means accounting unbundling, not ownership unbundling
   - How to estimate 31 December accounting data before the year is over?
     - HEP Transmission provided data on book value at 31.12.2001
     - The book value of assets at 31.12.2002 was forecast in October 2002, based on capital expenditure plans for 2002

Valuation of assets: book value at 31.12.2001

Valuation of the assets of HEP transmission at 31.12.2001

	Category of assets	Depre-ciation lifetime, years	Percentage depreciation reflected in book value	Book value of initial cost reported at 31.12.2001, kunas	Book value of accumulated depreciation at 31.12.2001, kunas	Book value of initial cost less depreciation at 31.12.2001, kunas
1	Transformer stations 400/x kV	30	82.1%	340,186,592	279,250,496	60,936,096
2	Transformer stations 220/x kV	30	82.2%	376,554,856	309,347,168	67,207,688
3	Transformer stations 110/x kV	30	61.4%	1,629,444,570	1,001,139,807	628,304,763
4	Transmission lines 400 kV	30	46.6%	1,078,825,760	502,843,172	575,982,588
5	Transmission lines 220 kV	30	77.6%	578,236,215	448,505,173	129,731,042
6	Transmission lines 110 kV	30	58.9%	2,301,318,145	1,354,550,658	946,767,487
7	Other HEP transmission assets	30	76.5%	663,838,702	507,963,172	155,875,530
8	Land		0.0%	161,911,667	0	161,911,667
9	Total	30	61.8%	7,130,316,507	4,403,599,646	2,726,716,861

Nexant 5

Short comments on asset values

- War damage means that assets are overvalued, unless the value of war damage is subtracted from the balance sheet. What to do? Nothing.
  - We assume that transmission companies will not be privatized. What is important is creditworthiness.
- Original costs are meaningless, due to inflation
  - Depreciated replacement cost would be "correct"
- If a category of assets is 80 percent depreciated, there is a good chance that these assets will be replaced or rebuilt ---> bad news for the customer

Nexant 6

Importance of asset values

- Transmission companies do not keep an account of operation and maintenance expenses by voltage level but
- The transmission tariff should reflect the true cost of service at 400, 220 kV or at 110 kV or at the Medium Voltage side of the 110/x transformer. What to do?
  - Option A: look at the ratios among asset values by voltage level, and allocate all costs based on assets
  - Option B: look at the sales tariff at different voltage levels and estimate the transmission "share"

A guide to font colors in the Excel tables

- Figures in blue are actual, historical input data
- Figures in red are input assumptions used in October 2002 for the preliminary estimate of the transmission fee
- Figures in green are input numbers that are not even close to the preliminary estimates, because the data are confidential
- Figures in black are calculated from formulas, or are equal to the input data
  - During the interactive simulation, please change the blue, red, or green input values but not the black cells!

Valuation of assets: estimate for 31.12.2002

Assets in service from 31.12.2001 to 31.12.2003						
			Less:	Plus:	Plus:	Equals:
	Category of assets	Book value of initial cost reported at 31.12.2001, kunas	Assets fully depreciated at 31.12.2002, kunas	New assets brought into service in 2002, kunas	Replacement & reconstruction of existing assets in 2002, kunas	Book value of initial cost reported at 31.12.2002, kunas
1	Transformer stations 400/x kV	340,186,592			18,713,360	358,899,952
2	Transformer stations 220/x kV	376,554,856			18,713,360	395,268,216
3	Transformer stations 110/x kV	1,629,444,570			18,713,360	1,648,157,930
4	Transmission lines 400 kV	1,078,825,760		0	18,713,360	1,097,539,120
5	Transmission lines 220 kV	578,236,215		0	18,713,360	596,949,575
6	Transmission lines 110 kV	2,301,318,145		42,595,000	18,713,360	2,362,626,505
7	Other HEP transmission assets	663,838,702				663,838,702
8	Land	161,911,667				161,911,667
9	Total	7,130,316,507	0	42,595,000	112,280,161	7,285,191,668

Nexant 9

Step 2

⌘ **2. Definition of customer classes, by voltage level**

- **The number of customer classes should be small**
  - The best approach is to separate customers by voltage level
  - A "transmission customer" is an entity that pays for transmission service
- **No discrimination based on "captive" vs. "eligible"**
  - What if the existing customer classes do not make any sense? The transmission company will have to propose new ones
- **Is tariff harmonization possible in South East Europe?**
  - Maybe - but this depends on voltage levels at Extra High Voltage and High Voltage. Distribution is another story entirely!

Nexant 10

Proposed customer classes for transmission service in Croatia

- **Delivery at 400 or 220 kV**
  - The transmission customer supplies energy to the grid at 400 or 220 kV, and receives energy at 400 or 220 kV
  - These customers are transit or export customers
- **Delivery at 110 kV**
  - The transmission customer supplies energy at 400, 220, or 110 kV, and receives energy at 110 kV
  - These customers own 110/x kV transformers
- **Delivery at 30, 20, 10 kV**
  - Customer supplies energy at 400, 220, 110 kV or medium voltage
  - Customer receives energy at 30, 20, or 10 kV from 110/x kV transformers owned by HEP Transmission

Step 3

- **3. Identification of services to be provided, and standards of service quality**
  - UCTE data (available online) and HEP data were used to evaluate power quality in Croatia's high voltage network
  - "Customer minutes lost" are not measured
  - Given the high reliability and power quality in the Croatian transmission grid, the tariff working group decided that there is no need to develop power quality standards for HEP transmission

Step 4

⌘ **4. Selection of a method to value electric energy losses**

- ☒To support unbundling of accounts, this method should not depend on generation costs or supply costs of any HEP Group company
- ☒Simplest approach is to use a European spot market price, averaged over a period of at least 6 months
  - The EEX 200-day average was selected
- ☒The working group also looked at transmission system energy losses in EU countries and decided that 4 % losses are reasonable and acceptable for Croatia

Treatment of the cost of energy losses

⌘ **Energy losses should be included in the transmission fee**

- ☒This recommendation was based on a review of European experience. Most (but not all) EU countries follow this principle

⌘ **This cost should be included in the lp/kWh component of the two-part transmission fee**

- ☒This cost is related to energy, not capacity

⌘ **To estimate the annual average value of electric energy, use the 200-day average price at www.eex.de**

- ☒European Electricity Exchange prices in Euro/MWh

Step 5

⌘ **5. Forecast of demand and capital expenditure**

☒Demand forecast: peak MW delivered and annual GWh delivered from the transmission system to transmission customers

- *output* from the transmission grid, not *input*
- excluding technical losses
- commercial losses = 0
- excluding energy used in pumped storage hydro

☒Capital expenditure forecast includes:

- replacement and reconstruction of existing assets
- new assets (for example, new interconnections)
- all expenditures - including investments needed to provide import, export, and transit service

Demand: estimate for 2002 & forecast for 2003

Energy Demand, Winter Peak Load, and Energy Losses

		Voltage level									
		110 kV	220 kV	400 kV							
Table	Year	(distribution + eligible customers)	(eligible customers)	(eligible customers)	Total	Loop flow	Distribu-tion	Direct consump-tion	Other consump-tion	Total at 110 kV	Total system
1	Demand (MWh)						Demand (GWh)				
	2000	13,197,337	0	0	13,197,337		12,582.0	552.5	62.8	13,197.3	
	2001	13,826,673	0	0	13,826,673		13,199.1	534.7	92.9	13,826.7	
	2002	14,229,047	0	0	14,229,047		13,583.2	550.3	95.6	14,229.0	
	2003(forecast)	14,631,420	0	0	14,631,420		13,967.3	565.8	98.3	14,631.4	
2	Winter Peak Load (MW) (24.12. 17:30 h)										
	2000	2,353	0	0	2,353	547					2,661
	2001	2,674	0	0	2,674	484					2,796
	2002	2,810	0	0	2,810	510					
	2003 (forecast)	2,950	0	0	2,950	450	2,816.1	114.1	19.8	2,950.0	
4	Energy losses (MWh)										
	2000				638,826						
	2001				628,536						
	2002(I-VIII 2002)				463,481						
	2003(forecast)				659,960						

Valuation of assets: forecast for 2003

Assets in service from 31.12.2001 to 31.12.2003

	Category of assets	Book value of initial cost reported at 31.12.2001, kunas	Less: Assets fully depreciated at 31.12.2002, kunas	Plus: New assets brought into service in 2002, kunas	Plus: Replacement & reconstruction of existing assets in 2002, kunas	Equals: Book value of initial cost reported at 31.12.2002, kunas	Less: Assets fully depreciated at 31.12.2003, kunas	Plus: New assets brought into service in 2003, kunas	Plus: Replacement & reconstruction of existing assets in 2003, kunas
1	Transformer stations 400/x kV	340,186,592			18,713,360	358,899,952		200,000,000	#N/A
2	Transformer stations 220/x kV	376,554,856			18,713,360	395,268,216		200,000,000	#N/A
3	Transformer stations 110/x kV	1,629,444,570			18,713,360	1,648,157,930		200,000,000	#N/A
4	Transmission lines 400 kV	1,078,825,760		0	18,713,360	1,097,539,120		210,200,000	#N/A
5	Transmission lines 220 kV	578,236,215		0	18,713,360	596,949,575		137,050,000	#N/A
6	Transmission lines 110 kV	2,301,318,145		42,595,000	18,713,360	2,362,626,505		96,143,000	#N/A
7	Other HEP transmission assets	663,838,702				663,838,702			
8	Land	161,911,667				161,911,667			
9	Total	7,130,316,507	0	42,595,000	112,280,161	7,285,191,668	0	1,043,393,000	117,442,667

Transmission lines 220 kV funded by 123 million Euro loan: 100,000,000
New assets in the medium term investment plan: 133,193,000

Nexant 17

Step 6

- **6. Selection of a 12-month period in which the tariff will be in effect**
  - **The tariff working group chose calendar year 2003**
    - In 2002, HEP Transmission did not forecast the data needed to calculate a tariff for 2004 or later
    - In 2003, HEP Transmission developed forecasts for 2004-2007. This is a very good idea because 2003 is not a "typical" year from the standpoint of debt financing
  - **In fact, the transmission tariff was not implemented on 01.01.2003. Could it be implemented on 01.07.2003?**

Nexant 18

Step 7

⌘ **7. Forecast of operation and maintenance expenses**

- ☒HEP Transmission estimated operation and maintenance costs in January 2002. This was the easiest part of the tariff calculation
- ☒Normally there is no evidence of waste, fraud, or inefficiency in transmission operations. These problems arise in generation and in metering, billing, and service to low-voltage customers

Operation and maintenance expenses

Transmission fee calculation, 2003

			Revenue target for 2003	Revenue target, lp/kWh	Revenue target, Euro/kWh	Costs allocated to demand	Costs allocated to energy	Pricing assumption	
	Depreciation								
1	Depreciation	Kuna	237,442,667	1.63	0.22	237,442,667			
	Operation and maintenance expenses								
2	Operation and maintenance	Kuna	60,000,000	0.41	0.06	60,000,000			
3	Salaries and related expenses	Kuna	60,000,000	0.41	0.06	60,000,000			
4	Vehicles, guarding services, telecommunication and other costs	Kuna	60,000,000	0.41	0.06	60,000,000			
5	Reactive energy production, equal to 1000 Gvarh x 1.25 lp/kvarh	Kuna	12,500,000	0.09	0.01		12,500,000	0.0125	Kuna /kvarh
6	Transmission system losses	Kuna	107,441,488	0.74	0.10		107,441,488	22.0	Euro /MWh
7	Common services of HEP d.d. including accounting & financial, personnel, legal, IT, public relations	Kuna	60,000,000	0.41	0.06	60,000,000			

Figures in green are not even close to the true numbers, which are confidential

Step 8

- **8. Setting of financial objectives; definition of financial targets for HEP Transmission**
  - No plans for privatization
  - At present HEP d.d. (representing HEP Group) holds long-term debt obligations and the funds are made available to the HEP Group companies
  - For 2003 the working group assumed no new long-term loans would become available to cover capital expenditures
  - Although there is no need for a "profit" component in the tariff calculation, it is necessary to include a capital expenditure allowance. The effect of this allowance is to increase shareholder equity in the balance sheet, so "profit" may accrue indirectly

Loan financing

- **A 123 million Euro loan was signed by HEP Group in 2002 to support reconstruction of:**
  - transformer station 400/110 kV Ernestinovo
  - the high voltage network related to Ernestinovo
  - transformer substation 400/220/110 kV Žerjavinec
- **The tariff working group had to make very rough estimates of principal and interest payments**
  - The financing terms are favorable to HEP. A key assumption is that in 2003 there will be no principal payments on this loan
  - Later, in 2003, HEP "unbundled" its long-term debts

Principal & interest payments on a major loan

Repayment of the 123 million Euro loan

			2002	2003
	Loan interest rate, LIBOR		4.0%	4.0%
	Exchange rate, Kuna/Euro		7.40	7.40
	Capital expenditures financed by this loan	Euro	60,000,000	63,000,000
	Principal at January 31	Kuna	0	444,000,000
Plus:	Capital expenditures financed by this loan	Kuna	444,000,000	466,200,000
Less:	Principal payment	Kuna	0	0
Equals:	Principal at December 31	Kuna	444,000,000	910,200,000
	Interest payment	Kuna	11,100,000	33,855,000
	Premium over LIBOR:		1%	
	Years in which principal is repaid:		#N/A	
	Interest rate on cash reserves held in Kuna:		7.0%	7.0%

Nexant 23

The estimate of depreciation in 2003 is based on 31.12.2002 asset values

Depreciation, 2002-2003

	Category of assets	Book value of initial cost less depreciation at 31.12.2001, kunas	Less: Depreciation in 2002, kunas	Plus: New assets plus replacement & reconstruction in 2002, kunas	Equals: Book value of initial cost less depreciation at 31.12.2002, kunas	Less: Depreciation in 2003, kunas
1	Transformer stations 400/x kV	60,936,096	11,339,553	18,713,360	68,309,903	11,963,332
2	Transformer stations 220/x kV	67,207,688	12,551,829	18,713,360	73,369,220	13,175,607
3	Transformer stations 110/x kV	628,304,763	54,314,819	18,713,360	592,703,304	54,938,598
4	Transmission lines 400 kV	575,982,588	35,960,859	18,713,360	558,735,090	36,584,637
5	Transmission lines 220 kV	129,731,042	19,274,541	18,713,360	129,169,862	19,898,319
6	Transmission lines 110 kV	946,767,487	76,710,605	61,308,360	931,365,242	78,754,217
7	Other HEP transmission assets	155,875,530	22,127,957	0	133,747,573	22,127,957
8	Land	161,911,667			161,911,667	
9	Total	2,726,716,861	232,280,161	154,875,161	2,649,311,861	237,442,667

Nexant 24

Assumptions regarding capital investment

⌘ **The tariff working group assumed that:**

- ☒Cash flow from depreciation will be used to pay for capital expenditures for replacement and reconstruction of existing assets, plus principal payments on long-term debt
- ☒A special *"capital expenditure allowance"* should be included in the target level of annual revenue, to pay for capital expenditures in the medium term investment plan

Sources and uses of funds: forecast

Cash flow, 2002 - 2003					
				2002	2003
1		Cash reserves at January 1	Kuna	5,000,000	5,350,000
2	Plus:	Interest earned on cash reserve	Kuna	350,000	374,500
3	Plus:	Cash flow provided by depreciation	Kuna	232,280,161	237,442,667
4	Plus:	Cash flow provided by the "new facilities" component of the trans. fee	Kuna	42,595,000	133,193,000
5	Plus:	Cash flow provided by the 123 million Euro loan	Kuna	444,000,000	466,200,000
6	Less:	Capital expenditures related to the 123 million Euro loan	Kuna	444,000,000	466,200,000
7	Less:	Capital expenditures related to the medium term investment plan	Kuna	42,595,000	133,193,000
8	Less:	Capital expenditures for replacement and reconstruction of existing assets	Kuna	112,280,161	117,442,667
9	Less:	Principal payment on long-term debt other than the 123 million Euro loan	Kuna	120,000,000	120,000,000
10	Less:	Principal payment on 123 million Euro loan	Kuna	0	0
11	Less:	Cash transfers to HEP Group	Kuna	0	0
12	Equals:	Cash reserves at December 31	Kuna	5,350,000	5,724,500

Step 9

⌘ **9. Forecast of the annual revenue requirement**

☒This is the target level of annual revenue that HEP Transmission would need in 2003 to cover:

Operating costs + energy losses + interest expense + capital expenditures

Nexant 27

Transmission fee calculation, 2003

			Revenue target for 2003	Revenue target, lp/kWh	Revenue target, Euro/kWh	Costs allocated to demand	Costs allocated to energy
	Depreciation						
1	Depreciation	Kuna	237,442,667	1.63	0.22	237,442,667	
	Operation and maintenance expenses						
2	Operation and maintenance	Kuna	60,000,000	0.41	0.06	60,000,000	
3	Salaries and related expenses	Kuna	60,000,000	0.41	0.06	60,000,000	
4	Vehicles, guarding services, telecommunication and other costs	Kuna	60,000,000	0.41	0.06	60,000,000	
5	Reactive energy production, equal to 1000 Gvarh x 1.25 lp/kvarh	Kuna	12,500,000	0.09	0.01		12,500,000
6	Transmission system losses	Kuna	107,441,488	0.74	0.10		107,441,488
7	Common services of HEP d.d. including accounting & financial, personnel, legal, IT, public relations	Kuna	60,000,000	0.41	0.06	60,000,000	
	Interest expense					0	
8	Interest payment on long-term debt other than the 123 million Euro loan	Kuna	60,000,000	0.41	0.06	60,000,000	
9	Interest payment on the 123 million Euro loan	Kuna	33,855,000	0.23	0.03	33,855,000	
10	Interest on short-term debt	Kuna	22,100,000	0.15	0.02	22,100,000	
	Capital expenditure allowance					0	
11	Capital expenditures related to the medium term investment plan	Kuna	133,193,000	0.92	0.12	133,193,000	
12	Annual revenue requirement	Kuna	846,532,155	5.82	0.79	726,590,667	119,941,488

Nexant 28

Step 10

- **10. Design of the tariff: capacity and energy charges**
  - **In 2002 the proposal considered by the working group was based on costs, and not related to the sales tariff to final customers**
    - Energy charges cover energy losses plus reactive power costs
    - Demand charges cover all other expenses including capital expenditures
  - **The Excel spreadsheet is very simple, however, so costs could be shifted to the energy charge**
    - On the following pages we present the original proposal

Recovery of the annual revenue target in 1-part and 2-part tariff structures

Transmission fee calculation, 2003						
			Revenue target for 2003	Revenue target, lp/kWh	Revenue target, Euro/kWh	Costs allocated to demand
12	Annual revenue requirement	Kuna	846,532,155	5.82	0.79	726,590,667
	Monthly revenue requirement	Kuna				60,549,222
This methodology does not include any allowance for income tax to be paid by HEP Transmission.						
One-part transmission fee						
	Customer demand at 110 kV and MV	MWh	14,533,113			
	Fee charged to all customers in Croatia	lp/kWh	5.82			
	(no transmission fee for import or export)					
Two-part transmission fee: energy component						
	Customer demand at 110 kV and MV	MWh	14,533,113			
	Export demand	MWh	1,000,000			
	Customer demand + Export demand	MWh	15,533,113			
	Energy-related component collected from					
	Croatian customers + export customers	lp/kWh	0.77			

Demand charges can be calculated on the basis of asset value

Demand-related component for 3 customer classes

	Depreciation in 2003, Kuna	Percent of total	Cost allocated to demand in 2003, Kuna/month	Delivery to Export Customers at 400, 220 kV, kW	Delivery to Direct Customers at 110 kV, kW	Delivery to Distribution at 110 kV, kW	Delivery to Distribution at 35,20,10 kV, kW	Delivery to all Transmission customers, kW	Demand-related component, Kuna/ kW/ month
Assets used to provide delivery at all voltage levels									
Transmission lines 400 kV	36,584,637	15.4%	9,329,289	100,000	114,081	563,220	2,252,879	3,030,179	3.08
Transmission lines 220 kV	19,898,319	8.4%	5,074,184	100,000	114,081	563,220	2,252,879	3,030,179	1.67
Transformer stations 400/x kV	11,963,332	5.0%	3,050,717	100,000	114,081	563,220	2,252,879	3,030,179	1.01
Other HEP transmission assets	22,127,957	9.3%	5,642,754	100,000	114,081	563,220	2,252,879	3,030,179	1.86
EHV users' subtotal	90,574,245	38.1%	23,096,944						7.62
Assets used to provide delivery at 110, 30, 20, 10 kV									
Transformer stations 220/x kV	13,175,607	5.5%	3,359,854		114,081	563,220	2,252,879	2,930,179	1.15
Transmission lines 110 kV	78,754,217	33.2%	20,082,770		114,081	563,220	2,252,879	2,930,179	6.85
EHV+HV users' subtotal	182,504,069	76.9%	46,539,569						15.62
Assets used to provide delivery at 30, 20, 10 kV									
Transformer stations 110/x kV	54,938,598	23.1%	14,009,653				2,252,879	2,252,879	6.22
EHV+HV+MV users' subtotal	237,442,667	100.0%	60,549,222						21.84

Demand charges

- **Alternative ways to bill a customer for MW demand:**
  - **the customer's annual maximum demand**
    - This is what we selected
  - **the customer's demand at the system peak hour**
    - too difficult to estimate
  - **the customer's monthly maximum demand**
    - not a good idea! There is no logic behind this
  - **the customer's contractual maximum demand**
    - This is not fair to the customer, if the tariff design is radically changed and costs are shifted to the demand charge

Target monthly revenue - demand charges

	Delivery to Export Customers at 400, 220 kV	Delivery to Direct Customers at 110 kV	Delivery to Distribution at 110 kV	Delivery to Distribution at 35,20,10 kV	Delivery to all Transmission customers	Delivery to Distribution at all voltages
Transformer capacity 110/x kV in 2001, in MVA			1,114.5	4,504.0		5,618.5
Share of transformer capacity 110/x kV in 2001, in MVA			19.8%	80.2%		100.0%
Share of energy and load at 110/x kV (estimated)			20.0%	80.0%		100.0%
Energy delivered by the transmission network in 2001, GWh	587.8	534.7	2,639.8	10,559.3	14,321.6	13,199.1
Winter peak load supplied by the transmission network in 2003, kW*	100,000	114,081	563,220	2,252,879	3,030,179	
Demand-related component, Kuna/kW/month	7.62	15.62	15.62	21.84		
Revenue collected from the demand-related component, Kuna/month	762,230	1,782,256	8,799,017	49,205,720	60,549,222	

Step 11

⌘ 11. Calculation of the proposed tariff

- ☒In theory it may be possible to calculate the tariff and then go back to assumptions about debt financing and capital expenditure, and revise the input data. In 2002 we had no time to do this
- ☒In calculating a sales tariff to household customers it is normal to propose a "transition period" to higher tariffs. For the transmission tariff we assumed there will be no transition period
- ☒The big question is the level of the capital expenditure allowance

2-part transmission fee: sample calculation

Type of fee	Customer class	Calculated value	Monthly revenue, million Kuna	Annual revenue, million Kuna
Capacity	Delivery at 400 or 220 kV	7.62 Kuna/ kW/ month	0.762	9.146
Capacity	Delivery at 110 kV	15.62 Kuna/ kW/ month	10.581	126.973
Capacity	Delivery at 30, 20, 10 kV	21.84 Kuna/ kW/ month	49.206	590.472
Capacity	All customers		60.549	726.591
Energy	All customers	0.77 lp/kWh		119.941
Total	All customers			846.532

Nexant 35

Closing remarks

- **New transmission companies are in a special situation**
  - Accounts are not yet unbundled
  - Profit objectives are undefined, or else "zero profit" is assumed
  - Investments are needed to support export, import and transit but it is not clear who is really going to pay for these investments
  - A CBT mechanism in South East Europe does not yet exist
- **This approach was designed to help HEP Transmission start to work as a functionally independent company**
  - The process of setting transmission tariffs is an important step toward achievement of the objectives of the Athens Memorandum

Nexant 36

15

TRANSMISSION NETWORK FEES FOR CROATIA

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Table of Contents

CHAPTER 1 EXECUTIVE SUMMARY **1**

1.1 Objectives of this study 1
1.2 Recovery of the cost of electric energy losses in the transmission system 1
1.3 Transmission fee components needed to cover capital investment needs 1
1.4 Proposed customer classes and two-part transmission fee 2
1.5 Proposal for an initial one-part transmission fee 3
1.6 Incentive regulation 4

CHAPTER 2 ELECTRICITY TRANSMISSION TARIFFS IN EUROPE **5**

2.1 The Benchmark of Electricity Transmission Tariffs report 5
2.2 Weaknesses of the *Benchmark* report 6
2.3 Definition of the assets of the transmission networks 7
2.4 Transmission Asset Owners and System Operators 8
2.5 Charges to producers and charges to consumers 9

CHAPTER 3 TREATMENT OF ENERGY LOSSES IN EUROPEAN TRANSMISSION TARIFFS **11**

3.1 Level of technical losses 11
3.2 Time differentiation and geographic differentiation of transmission losses 12
3.3 Requirements of the EU Electricity Directive regarding transmission tariffs 13
3.4 Methods of recovering the cost of energy losses 15
3.5 Energy losses and transmission tariffs in Western Europe 16
3.6 Proposal for Croatia 17
3.7 Should the transmission loss component be time-differentiated? 17

CHAPTER 4 IDENTIFICATION AND VALUATION OF TRANSMISSION ASSETS **18**

4.1 Separation of transmission, distribution, and generation 18
4.2 Valuation of assets owned by HEP Transmission 19
4.3 Stranded costs 21
4.4 Depreciation charges 22

CHAPTER 5 DEFINITION OF CUSTOMER CLASSES **23**

5.1 Proposed definition of transmission customer classes 23

CHAPTER 6 COSTS TO BE RECOVERED THROUGH THE TRANSMISSION FEE, ISMO CHARGES, AND BALANCE POWER PRICES **24**

6.1 Legal framework for system fees and charges in Croatia 24
6.2 Proposal prepared by the ISMO 25
6.3 Why balance power must be provided 26
6.4 Proposal for balance power pricing in Croatia 27
6.5 Balance power providers in the Swedish electricity market 27

CHAPTER 7 VALUATION OF ENERGY LOSSES IN THE HV NETWORK **30**

7.1 Quantity of electric energy losses 30
7.2 Selecting a method of valuing energy losses 31
7.3 Terms of the agreement between HEP Transmission and its supplier 32
7.4 Time differentiation of losses 33
7.5 Valuation method used in the tariff calculation 33

CHAPTER 8 TRANSIT FEES IN EUROPE **34**

8.1 What is electricity transit? 34
8.2 Transmission tariffs in western Europe since March 2002 37
8.3 Transmission tariffs that existed in Europe before March 2002 40
8.4 Implications for HEP Transmission 42

CHAPTER 9 TRANSMISSION FEE COMPONENTS NEEDED TO COVER CAPITAL INVESTMENT NEEDS **43**

CHAPTER 10 CALCULATION OF THE TRANSMISSION FEE **45**

10.1 General approach and procedure 45
10.2 Structure of the transmission fee 46
10.3 Import, export, and transit 47
10.4 Transition to the two-part fee 50
10.5 Calculated results 50

CHAPTER 11 INCENTIVE REGULATION **52**

11.1 HEP Transmission Functions 52
11.2 Distinguishing the "owner" from the "operator" 53
11.3 Absence of a profit motive 55
11.4 Regulatory incentives 57

CHAPTER 12 LONG RUN MARGINAL COST OF TRANSMISSION **59**

APPENDIX A EXCEL WORKSHEET: HEP TRANSMISSION FEE FOR 2003

Valuation of the assets of HEP transmission at 31.12.2001 1
Assets in service from 31.12.2001 to 31.12.2003 2
Depreciation, 2002 - 2003 3
Cash flow, 2002 – 2003; Repayment of the 123 million Euro loan 4
Energy demand, winter peak load, energy losses 5
Transmission fee calculation, 2003 6
Demand-related component for 3 customer classes 7

Chapter 1 Executive Summary

1.1 Objectives of this study

According to Article 12 of the Law on Electricity Market, "The Energy Regulatory Council shall set electricity transmission fees and distribution fees upon the proposal of the energy undertaking carrying out transmission or distribution of electricity, respectively." The objective of this report is to assist HEP Transmission, a daughter company of HEP Group, in calculating a transmission fee that will support a liberalized electricity market, consistent with Croatian law, consistent with the EU Electricity Directive and current industry practices in Europe.

This report was prepared by Nexant Inc. under a subcontract with Pierce Atwood, based on data provided by HEP Transmission and on the decisions taken by the transmission fee working group organized in June 2002 for the purpose of guiding this study. The Excel spreadsheet accompanying this report is presented in Appendix A. This transmission fee analysis represents a cooperative effort among the Ministry of Economy of the Republic of Croatia; HEP Transmission; the Croatian Energy Regulatory Council; and the United States Agency for International Development.

The original version of this report dated 6 November 2002 contains confidential information about international power flows and operating expenses of HEP Transmission, which have been deleted from this version of the report. As a result the two-part transmission fee shown in this report are only illustrative numbers based on a sample calculation. Because the one-part transmission fee is not affected by export and import data or by the composition of operating expenses, the final result shown in this report is the same as in the November 2002 draft.

1.2 Recovery of the cost of electric energy losses in the transmission system

On the basis of transmission fee structures in western Europe it is recommended that the cost of energy losses should be included in the HEP transmission fee and charged to customers on a lp/kWh basis. The value of the electric energy may be estimated from the 200-day average price in Euro/MWh of energy traded on the European Electricity Exchange using publicly available data from www.eex.de .

1.3 Transmission fee components needed to cover capital investment needs

In developing a forecast of the revenue that should be collected through the transmission fee, it is important to ensure that HEP Transmission will have enough cash flow to pay for the capital expenditure program and for principal and interest payments on long-term debt. The expenses to be covered by the transmission fee should include depreciation and interest expense, which are normally included in a calculation of use of network fees for any transmission or distribution network owner. Interest on short-term debt should be also included in the tariff calculation. There is no need for HEP Transmission to earn a return on equity. In this report transmission fees for the year 2003 were calculated on the basis of the following assumptions:

1. Depreciation is used to pay for capital expenditures for replacement and reconstruction of existing assets, plus principal payments on long-term debt

2. In 2003 there will be no principal payments on the 123 million Euro loan that was signed by HEP Group in 2002 to pay for the construction of the transformer station 400/110 kV Ernestinovo, the high voltage network related to Ernestinovo, and the transformer substation 400/220/110 kV Žerjavinec which is located near Zagreb.

3. To pay for the medium term investment plan in 2003, HEP Transmission should collect these funds by increasing the transmission fee. A special "capital expenditure allowance" should be included in the transmission fee. At present it is not appropriate for HEP Transmission to seek debt financing for the medium term investment plan, which involves 133,193,000 Kuna of capital expenditure in 2003 for new assets. This is equivalent to 18.6 million dollars, at an exchange rate of 7.18 Kuna per dollar.

1.4 Proposed customer classes and two-part transmission fee

For the HEP Transmission system, three customer classes are proposed:

1. **Delivery at 400 or 220 kV**: The transmission customer supplies energy to the transmission grid or makes contractual arrangements to supply energy at 400 or 220 kV, and receives energy at delivery points on the 400 or 220 kV network. These customers are transit or export customers.

2. **Delivery at 110 kV**: The transmission customer supplies energy to the transmission grid or makes contractual arrangements to supply energy at 400, 220, or 110 kV, and receives energy at delivery points on the 110 kV network. These customers own 110/x kV transformers.

3. **Delivery at 30, 20, 10 kV**: The transmission customer supplies energy to the transmission grid or makes contractual arrangements to supply energy at 400, 220, 110 kV, or medium voltage, and receives energy at 30, 20, or 10 kV from 110/x kV transformers owned by HEP Transmission.

For HEP Transmission in 2003 all customers should have a subscription period of one year, for the purpose of defining the peak load in kW which must be multiplied by the capacity fee in Kuna per kW per month. There should be a uniform energy charge to all consumers.

The 400 kV and 220 kV network of Croatia is assumed to be part of the *horizontal network* that will be defined by the European Transmission System Operators Association (ETSO). The costs of the horizontal network in Croatia should be shared with the TSOs in Slovenia, Hungary, and western Europe. Although HEP Transmission is not a member of ETSO, ELES (Slovenia) is a member of ETSO and MVM (Hungary) is an associate member. It is reasonable to assume that HEP Transmission will become an associate member of ETSO during the next two years. Therefore any HEP Transmission fee for export, import, or transit should be considered a temporary measure that will be eliminated or at least substantially changed after HEP Transmission joins ETSO.

For customers at 400 and 220 kV we assume that during the transitional period before ETSO membership HEP Transmission should apply a transmission fee to exports, but not

to import or transit, and that the fee should be applied to peak capacity in MW rather than energy in GWh. Both a capacity fee and an energy fee should be charged for exports. It does not matter whether the payment to HEP Transmission is made by the suppliers (located outside Croatia) who purchase the power that is exported, or by the producers (located in Croatia or elsewhere) who produce the power that is exported, or by some energy trading entity involved in the transaction.

The two-part transmission fee structure is as follows:

Type of fee	Customer class	Calculated value	Monthly revenue, million Kuna	Annual revenue, million Kuna
Capacity	Delivery at 400 or 220 kV	**7.62** Kuna/ kW/ month	**0.762**	
Capacity	Delivery at 110 kV	**15.62** Kuna/ kW/ month	**10.581**	
Capacity	Delivery at 30, 20, 10 kV	**21.84** Kuna/ kW/ month	**49.206**	
Capacity	All customers		60.549	726.591
Energy	All customers	**0.77** lp/kWh		119.941
Total	All customers			846.532

1.5 Proposal for an initial one-part transmission fee

To simplify the opening of the electricity market at the beginning of 2003 the transmission fee could consist simply of a fee in lp/kWh charged to all customers. There would be no fees for export, and there would be only one customer class:

- **Delivery at 110, 30, 20, 10 kV**: The transmission customer supplies energy to the transmission grid or makes contractual arrangements to supply energy at 400, 220, 110 kV, or medium voltage and receives energy at delivery points on the 110 kV network or at 30, 20, or 10 kV from 110/x kV transformers owned by HEP Transmission.

The one-part transmission fee structure for the beginning of 2003 is as follows:

Type of fee	Customer class	Calculated value	Monthly revenue, million Kuna	Annual revenue, million Kuna
Energy	All customers	5.82 lp/kWh		846.532

1.6 Incentive regulation

Given the legal framework noted above, the most effective way to reward good performance through the fee-setting process is to set specific targets for "Salaries and related expenses" and allow this line item to be increased by a certain percentage, based on good performance, for a period of no less than one calendar quarter. Additional transmission revenue could be collected by increasing the level of the energy charge per kWh (for example, the proposed **0.77** lp/kWh charge in a two-part transmission fee). The level of the energy charge per kWh could be adjusted on a quarterly basis, according to the firm's performance. The total cost of salaries are related expenses in 2003, excluding any reward for good performance, is estimated to be 0.79 lp/kWh and ideally this cost should be recovered through the demand charge; only the "extra" revenue should be allocated to the energy charge. In a two-part fee the demand charges should be stable.

The absence of a profit motive for HEP Transmission, coupled with the absence of "customer service" responsibilities and commercial quality indicators,[1] means that traditional Performance Based Ratemaking, as that term is customarily defined, does not apply in this context.[2] Instead, however, it appears that the incentive regulation could be included by adjusting target level of "salaries and related expenses" and adjusting the energy charge as noted above. If HEP Transmission contractually assumes certain operational functions, then additional indicators of good performance could be included in the evaluation that is used to adjust the target level of "salaries and related expenses" through adjustments in the energy component of the transmission fee.

The next step in defining such performance targets is to (1) identify more specifically targets and salary impacts for the core functions we know HEP Transmission will perform; and (2) resolve the nature of the ISMO-HEP Transmission relationship in order to determine whether HEP Transmission will assume additional functions so that the target level of "salaries and related expenses" can be adjusted on the basis of additional, more traditional performance targets.

---

[1] "Commercial quality concerns the quality of relationships between a supplier and a user." See R. Malaman et al., *Quality of Electricity Supply: Initial Benchmarking on Actual Levels, Standards, and Regulatory Strategies*, page 3. Prepared for the Council of European Energy Regulators, April 2001.

[2] "The fundamental principle behind PBR is that good utility performance should lead to higher profits, and poor performance should lead to lower profits." Bruce Biewald et al., *Performance-Based Regulation in a Restructured Electric Industry*, page 8. Prepared for the National Association of Regulatory Utility Commissioners, November 8, 1997.

Chapter 2 Electricity transmission tariffs in Europe

2.1 The Benchmark of Electricity Transmission Tariffs report

This report entitled *Benchmark of Electricity Transmission Tariffs* was completed in February 2002 by three experts at the Instituto de Investigación Tecnológica (Institute of Technical Research) of the Universidad Pontificia Comillas in Madrid. The report is funded by the European Commission, DG TREN, and the 17 countries covered in the report include Norway, Switzerland and the EU member countries (i.e. the countries whose transmission system operators were members of ETSO in 2001). It draws upon information in earlier reports prepared for the European Transmission System Operators Association (ETSO) and the Council of European Energy Regulators (CEER). Because Greece, Luxembourg, and Switzerland did not have an unbundled transmission tariff in February 2002 these countries are excluded from the analysis of transmission tariff design although they are included in the analysis of transmission system assets and costs.

Unlike most of the reports issued publicly by DG TREN, ETSO, and CEER this study contains a description of the actual transmission tariffs in Europe, rather than some sort of proposal for reform or cross-border tariffs. Although the report contains some policy recommendations to DG TREN, the report is fundamentally a description of what the tariffs are, and not an analysis of what they should be. Appendix 3 (Recompilation of Answers) contains a lot of useful information on a country-by-country basis. This is the best available survey of transmission tariffs in the EU member countries.

The main objective of the report is to compare the levels of transmission tariffs in the 17 countries, understand the reasons why some countries have higher tariffs than others, and suggest some of the next steps that would be desirable for "harmonizing" tariffs across all 17 countries, to promote the development of a single market for electricity. The concept of tariff harmonization is not precise, but harmonization could be defined as any tariff reform designed to make it easier for electricity market participants to implement bilateral agreements involving different countries. The report makes the following recommendations:

- Although different countries have very different methods of valuing transmission assets, and these differences result in different tariff levels, there is no need to try to establish a uniform approach to asset valuation in all 17 countries. There is no need to bring national average transmission tariffs (measured by annual transmission revenue per kWh consumed) to a uniform level.

- Transmission tariffs should be charged to consumers rather than producers; excluding connection charges for new generating units, the tariffs to producers should be zero, or very low. "The market distortions can be eliminated or minimized by setting the transmission charges of generators to zero or to some low number and/or avoiding energy charges to generators as much as possible."[3]

[3] *Benchmark of Electricity Transmission Tariffs*, page 20.

The report contains an interesting regression analysis showing that the total length of 400 and 220 kV transmission lines in a country (measured in km, with a weighting factor applied to 220 kV lines) is statistically related to three variables: the area of the country (km^2), the annual consumption of electricity (TWh), and annual per capita consumption.[4]

2.2 Weaknesses of the *Benchmark* report

Unfortunately the report has certain weaknesses:

1. The report places too much emphasis on countries, and not enough on companies. Instead of using the information available at the web sites of transmission system operators (for example, www.elia.be for Belgium, www.eirgrid.com for Ireland, and www.grtn.it for Italy) the report uses information from questionnaires sent to regulatory authorities in 2001, and from reports based on primary data sources that are somewhat out of date (i.e. two ETSO reports dated March 2000 and June 2000, and a CEER report dated September 2000).[5] Transmission tariffs are issued and approved for specific companies, not for countries, but the report attempts to present information by country and not by company. There are approximately 35 transmission companies in the EU countries plus Norway and Switzerland (see the "Organization" page at www.etso-net.org), and the electricity supply industry is in a period of transition in which new companies are being formed and mergers and acquisitions are taking place. Topics such as the selection of the Great Britain System Operator in accordance with the British Electricity Trading and Transmission Arrangements are not discussed at all, because the report is not based on the most recent information available on the Internet. The very helpful coordinating role of e-control (www.e-control.at) in the Austrian electricity market liberalization is not discussed. Therefore the report is too abstract and theoretical. Perhaps the idea of comparing countries, rather than companies, was related to some political agenda of the European Commission.

2. The report does not describe the different ways in which the electric sector is structured in the 17 countries. Most of these countries have only two network levels (transmission and distribution) but a few countries have three levels (national network, regional network, and local network). Most of the countries have a single national transmission asset owner which is also a transmission system operator, but some countries place these two functions in separate companies, and some countries have two or more transmission asset owners/system operators. Spain and Italy have a Market Operator. Obviously the structure of the power sector has an influence on the way the tariffs are calculated for the transmission asset owner.

3. In the analysis of transmission costs the report places far too much emphasis on the smaller countries. For example, to estimate "standardized costs" per km of 400 kV or 380 kV line, the correct method is to collect data on all of the 400 kV and 380 kV lines in the largest countries (or perhaps all 17 countries), discard any data points that

[4] *Benchmark of Electricity Transmission Tariffs*, pages 91-93. Some of the statements on pages 93 and 94 are incorrect, e.g. the statement that "additional explanatory factors are needed." In fact an R^2 of 0.977 is excellent; it is about as high as one can expect to obtain from this sort of analysis.

[5] Ignacio Pérez-Arriaga et al, *Benchmark of Electricity Transmission Tariffs*, February 2002, page 12.

represent "extreme" or "unique" situations, and estimate average costs per km. A similar analysis could be performed to estimate transformer cost per kVA. It is obvious that a great deal of weight will be given to France, Germany, Spain, Italy, Sweden, and England and Wales because those countries have a large number of km of transmission lines, and a lot of transformer capacity. The report takes a different approach – it presents estimates of "standard costs" by country.[6] As a result the data are difficult to understand. Given the limited resources available for the study it would have been better to limit the cost analysis to the six largest countries (ranked by km of transmission lines) rather than trying to analyze costs in 17 countries. While the legal and regulatory issues (for example, methods of valuing the assets of the transmission company) are worth examining in all 17 countries, the cost analysis probably could have been improved by narrowing the scope of the survey.

4. The report does not evaluate the pros and cons of different regulatory policies, different methods of asset valuation, or different ways of structuring Transmission Asset Owners and Transmission System Operators. It does not try to distinguish the "successful" countries from the "unsuccessful" countries or the "effective" regulators from the "ineffective" regulators. From a political standpoint, of course, this bland approach avoids controversy. No country is subject to criticism; the French are not criticized for allowing EdF to dominate the electric sector, the Germans are not criticized for the absence of an energy regulatory authority, and so forth. As a result the report is somewhat bland; it is like a report written by a committee for the purpose of pleasing 17 different governments.

The best way to place the report in proper perspective is to go to the web sites of each transmission company or independent transmission system operator, and the web sites of each energy regulatory authority, and look at the actual published tariffs and the statements made by the regulators about industry restructuring and tariff decisions. This requires a bit of work, of course. Most of the TSO web sites can be found at www.etso-net.org (although there are a few exceptions: www.eirgrid.com and www.nie.co.uk are not there) and all of the regulators' web sites can be found at www.ceer.org .

2.3 Definition of the assets of the transmission networks

The group of 17 countries do not have a common definition of "transmission" and "distribution" and therefore the countries use different concepts to distinguish transmission assets from distribution assets. A country-by-country description of how the transmission system is defined and the type of network assets is presented in Appendix 3.[7]

European networks have several different voltage levels: 400 kV, 380, 275, 225, 220, 150, 132, 110, 90, 63, 60, 50 and lower voltages. The networks from 400 through 220 kV are generally classified as Extra High Voltage (EHV) although there are exceptions such as Denmark where EHV is defined more broadly. The chart below illustrates the diverse mix of different voltage levels among the different countries.

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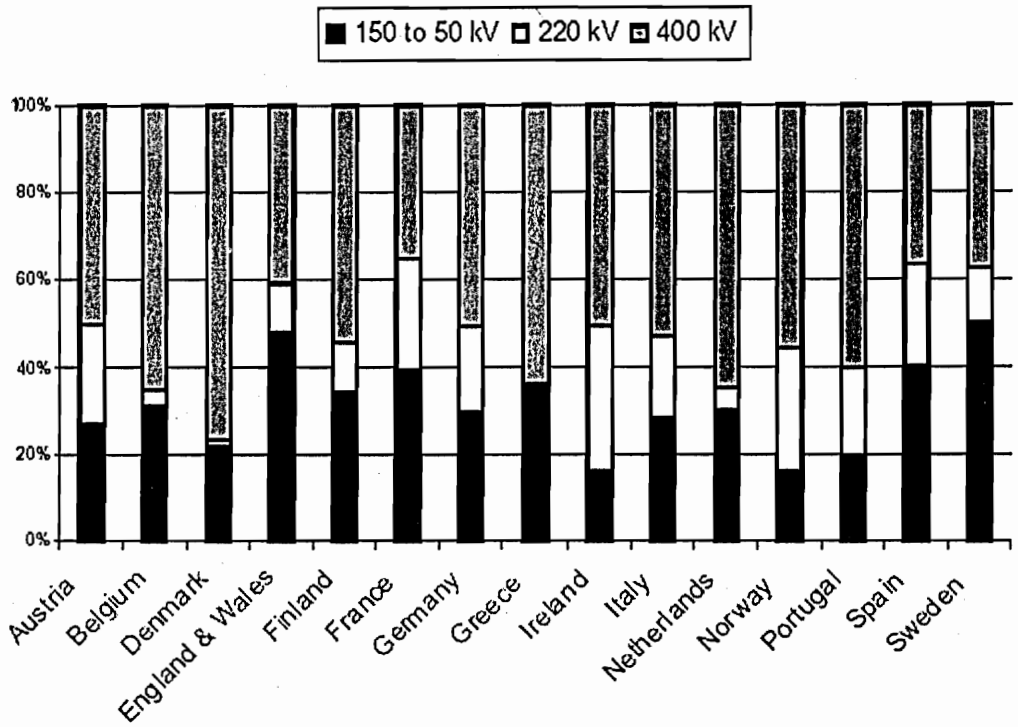
[6] *Benchmark of Electricity Transmission Tariffs*, page 76.

[7] *Benchmark of Electricity Transmission Tariffs*, pages 141-151.

Volume of transmission assets at different voltage levels



Source: *Benchmark of Electricity Transmission Tariffs*, page 73, Figure 28.

It is obvious that the "transmission system" energy losses vary by country, given the variation in the definition of the assets of the transmission system.

2.4 Transmission Asset Owners and System Operators

In three countries (Ireland, Italy, and the United Kingdom) the owner of transmission assets and the System Operator are separate legal entities.[8] In nine countries (Denmark, Finland, France, Germany, Netherlands, Norway, Portugal, Spain, Sweden) these functions are combined in one entity. In Austria these functions are also combined but the issues of pricing and settlement are coordinated by E-control Ltd. (www.e-control.at) which is also a regulatory authority. In Belgium the transmission system operator is a separate legal entity but it is possible that transmission assets will be transferred to this entity during the next phase of restructuring. In our analysis of transmission tariffs we ignore three countries - Greece, Luxembourg, and Switzerland -because there was no unbundled transmission tariff in these countries in February 2002 .

Because Croatia has chosen to separate the System Operator from HEP Transmission, the EU member countries whose experience is most relevant to the Croatian market model, with documentation in English, are Belgium and Ireland.

[8] To describe the electricity market structure the United Kingdom should be divided into Great Britain (England, Wales, Scotland) and Northern Ireland but the government and regulatory policy in these regions is quite similar and in fact the industry structure in Ireland is similar to the structure in the United Kingdom. The *Benchmarking* report describes the market in England & Wales, which is an outdated concept.

In Belgium the tariffs for access to the high voltage network are published in English at www.elia.be/english/4_4.htm . The tariff structure is very simple. There are four classes of transmission service customers:

1. Customers who own transformers connected to the 380/220/150 kV network. These customers pay Elia for use of the 380/220/150 kV wires but do not pay Elia for use of the transformers.

2. Customers who receive electricity from transformers that are owned by Elia and connected to the 380/220/150 kV network.

3. Customers who own transformers connected to the 70/36/30 kV network. These customers pay Elia for use of the 70/36/30 kV wires as well as the EHV wires and transformers.

4. Customers who receive electricity from transformers that are owned by Elia and connected to the 70/36/30 kV network.

Compensation for losses is included in the ancillary services charge, which is a tariff of about 3 Euro/MWh (the precise level depends on the customer class). It would be very easy to design transmission tariffs for Croatia, based on the Belgian model, if the "subscription for a period of one month" were deleted from the use of system tariff. Even the monthly subscription system could be introduced in Croatia, if necessary.

In Ireland the use of system tariffs are published by the regulatory authority in English at www.cer.ie and there is a wealth of information at that web site concerning the market structure and tariff concepts. Compensation for losses is not in the use of system tariffs; it is in the Transmission Loss Factors that are published by the Transmission System Operator at www.eirgrid.com (click on "Transmission").

In Italy the use of system tariffs are published by the regulatory authority www.autorita.energia.it and by the independent system operator www.grtn.it but most of the information is in Italian.

At this time there is no need to study the United Kingdom market structure very closely because it is still in a transitional period in which the British Electricity Trading and Transmission Arrangements (BETTA) have not been implemented. The GB System Operator has not been selected. The Transmission System Operator for Northern Ireland www.nie.co.uk/aboutus/ourbusiness_transmission.htm has not yet been separated from the Transmission Asset Owner for Northern Ireland. However a lot of information on the market design is available from www.dti.gov.uk and from www.ofgem.gov.uk .

2.5 Charges to producers and charges to consumers

The transmission fees in Belgium, eastern Denmark, France, Germany, Portugal, and Spain consist entirely of charges to consumers. This is a very good idea and it greatly simplifies the formation of regional electricity markets because it makes tariff harmonization easier. Unfortunately some of the other EU Member States and Norway have transmission charges to producers, and the question of how to design an inter-TSO compensation mechanism is therefore complicated politically. To promote the development of regional electricity trade in central Europe it would be a good idea for Croatia and its neighbors to

follow the example set by Belgium, France, and Germany, and charge transmission fees (other than connection charges) only to consumers.

Comparison of transmission tariff components in different countries, Euro/MWh

Revenues from the various transmission fee components are expressed in Euro/MWh for a typical factory consuming a constant load of 15 MW during 16 hours (from 8 h to 24 h) in working days, and no load in weekends (approximately 4200 hours per year).

	Fixed Generators	Energy Generators	Capacity Generators	Fixed Consumers	Energy Consumers	Capacity Consumers	Total
Austria	0.000	0.641	0.000	0.000	4.555	1.932	7.13
Belgium	0.000	0.000	0.000	0.018	2.828	5.993	8.84
Denmark (East)	0.000	0.000	0.000	0.000	6.526	0.000	6.53
Denmark (West)	0.000	1.076	0.000	0.000	4.120	0.000	5.20
England & Wales	0.000	0.695	1.625	0.000	1.423	4.343	8.09
Finland	0.000	0.242	0.000	0.000	3.474	0.000	3.72
France	0.000	0.000	0.000	0.017	3.858	4.449	8.32
Germany	0.000	0.000	0.000	0.000	0.997	4.198	5.20
Ireland	0.000	0.126	1.127	0.000	3.129	2.248	6.63
Italy	0.000	1.001	0.000	0.094	4.771	1.955	7.82
Netherlands	0.089	0.890	0.000	0.089	1.861	1.291	4.22
Norway	0.000	0.271	1.672	0.000	0.136	2.299	4.38
Portugal	0.000	0.000	0.000	0.000	3.263	4.715	7.98
Spain	0.000	0.000	0.000	0.000	7.418	2.942	10.36
Sweden	0.000	0.443	0.634	0.000	1.211	0.690	2.98

Source: *Benchmark of Electricity Transmission Tariffs*, page 38.

Chapter 3 Treatment of energy losses in European transmission tariffs

3.1 Level of technical losses

Average network losses for each voltage level in Germany were estimated in an ETSO report, as shown in the table below. Germany is the only country for which these estimates are presented in the *Benchmarking* report.[9]

Network losses, in percent

Level of network or transformation	Network losses in %
EHV network (380 and 220 kV)	1.0
Transformation EHV/HV	0.5
HV network (110 kV)	0.5
Transformation HV/MV	0.6
MV network (10 – 30 kV)	1.6
Transformation MV/LV	1.7
Low voltage (0.4 kV)	4.5
Distance component as of 100 km and for 100 km	0.5

If we define the EHV network as 380 and 220 kV lines plus substations required for transformation EHV to HV, average losses in the EHV network are 1.5 percent. If we define the HV network as 110 kV lines plus substations required for transformation HV/MV then average losses in the combined EHV plus HV network are 2.6 percent.

The German transmission grid contains 18,200 km of 380 kV lines, 22,000 km of 220 kV lines, and 59,000 MVA of transformer capacity 380/220/lower and in special cases the 110 kV network that carries out transmission functions.[10] According to the Verband der Elektrizitätswirtschaft (VDEW) the *anteil am Stromverbrauch* were 4.3 percent in the year 2000 but this data source does not include a definition of the *Stromnetzen.*[11]

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[9] *Benchmark of Electricity Transmission Tariffs*, pages 152-153 based on ETSO, *Identification of the Horizontal Network and Cost Related Infrastructure and Losses*, March 2000. The ETSO report is not publicly available at www.etso-net.org .

[10] *Benchmark of Electricity Transmission Tariffs*, pages 142 and 148.

[11] Press release, "Weniger Verluste beim Stromtransport," 22 July 2002, at www.strom.de .

The transmission network of France is a combined EHV plus HV network including 20,900 km of 400 kV lines, 26,300 km of 225 kV lines, 58,700 km of 90 kV and 63 kV lines, 121,100 MVA of transformers 400 kV, and 115,800 MVA of transformers 225 kV.[12] These facilities are owned by Gestionnaire du Réseau de Transmission d'Electricité (RTE).

> As concerns the energy purchased to make up for losses on the network, RTE's decision to launch calls for tender to introduce competition between the various European suppliers was instrumental in obtaining more favorable prices for RTE and in lowering the transmission cost by 50 M€. These energy losses correspond to 2.5% of the electricity conveyed over the French transmission network, i.e. about 12 billion kWh/year. They account for about 10% of the present transmission cost. Upon completion of these invitations to tender, seven, then seventeen French and English suppliers were selected for the purchase of firm and weekly and daily optional products.[13]

Losses on the main transmission grid of Norway in 1997 were 1.6 percent. Losses in the transmission grid of Finland in 1999 were 1.54 percent. Losses in the transmission network of Spain in 1999 were 1.5 percent of distributors' demand. Losses in the EHV grid of Portugal in 1998 were 1.4 percent. [14]

The transmission network of Czech Republic is an EHV plus HV system which excludes transformers HV/MV. It includes 3,367 km of 400 kV lines, 1,904 km of 220 kV lines, 210 km of 110 kV lines, 2,030 MVA of transformers 400/220 kV, 10,740 MVA of transformers 300/110 kV, and 4,000 MVA of transformers 220/110 kV. Transmission losses in 2001 were 714 GWh or 1.3 percent of the 55,274 GWh of energy transferred in the system.[15]

In its Annual Report 2001, Polskie Sieci Elektroenergetyczne (PSE) does not report transmission network losses. Total transmission and distribution losses and "statistical differences" in 2001 were14,158 GWh or 10.7 percent of the 131,818 GWh of electric energy supplied to the network.

3.2 Time differentiation and geographic differentiation of transmission losses

The Nordel countries (Denmark, Finland, Norway, Sweden) and Spain have electricity spot markets that are either owned by the transmission asset owners or formed by national governments in the process of power sector restructuring. It is not surprising that these countries use spot prices to establish time differentiation of transmission losses. Logically the British Electricity Trading and Transmission Arrangements (BETTA) may reflect very similar principles but the *Benchmarking* report does not contain a discussion of BETTA.

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[12] RTE, *Technical Results: French Electricity Supply Industry 2001*, page 4. *Benchmark of Electricity Transmission Tariffs*, page 147.

[13] RTE, *Presentation of Results 2001* (Paris, 4 April 2002), page 6.

[14] *Benchmark of Electricity Transmission Tariffs*, pages 152-154.

[15] ČEPS *Annual Report 2001*, pages 8 and 44

Italy, Norway and Sweden have different patterns of production and consumption in the north and the south, and therefore these countries have transmission tariffs with geographic differentiation in the tariff. The availability of hydro generation in the north of Norway and Sweden varies greatly, depending on water inflows. Surprisingly, there is enough transmission congestion in Ireland to justify the selection of a transmission tariff that provides "locational signals to new generators."[16]

Geographic differentiation and time differentiation of the cost of transmission losses is described in the table below.

Treatment of losses in the transmission tariff

	Losses Included in Tariff	Postage Stamp	Geographic differentiation	Time differentiation	Consumers pay	Producers pay	Responsibility of generators
Austria	✓	✓			✓		
Belgium	✓	✓			✓		
Denmark	✓	✓		✓	✓		
England & Wales		✓			✓		
Finland	✓	✓		✓	✓	✓	
France	✓	✓			✓		
Germany	✓	✓			✓		
Italy			✓			✓	✓
Ireland			✓			✓	✓
Norway	✓		✓	✓	✓	✓	
Netherlands	✓	✓			✓		
Portugal		✓			✓		✓
Sweden	✓		✓	✓	✓	✓	
Spain		✓		✓	✓		

Source: *Benchmark of Electricity Transmission Tariffs*, page 47.

3.3 Requirements of the EU Electricity Directive regarding transmission tariffs

Although Electricity Directive approved on 19 December 1996 is still part of EU legislation, it is important to recognize that the "single buyer" option in Article 18 is not very likely to be implemented and even the "negotiated access" option in Article 17 is not very widely implemented. Therefore "regulated access," which is described in paragraph 4 of Article 17, appears to be the most likely option for Croatia. The European Commission

[16] *Benchmark of Electricity Transmission Tariffs*, page 70.

has proposed a number of amendments to the Electricity Directive that have not been approved, and the text below contains the original 1996 wording.

> Article 17
> 1. In the case of negotiated access to the system, Member States shall take the necessary measures for electricity producers and, where Member States authorize their existence, supply undertakings and eligible customers either inside or outside the territory covered by the system to be able to negotiate access to the system so as to conclude supply contracts with each other on the basis of voluntary commercial agreements.
> 2. Where an eligible customer is connected to the distribution system, access to the system must be the subject of negotiation with the relevant distribution system operator and, if necessary, with the transmission system operator concerned.
> 3. To promote transparency and facilitate negotiations for access to the system, system operators must publish, in the first year following implementation of this Directive, an indicative range of prices for use of the transmission and distribution systems. As far as possible, the indicative prices published for subsequent years should be based on the average price agreed in negotiations in the previous 12-month period.
> 4. Member States may also opt for a regulated system of access procedure, giving eligible customers a right of access, on the basis of published tariffs for the use of transmission and distribution systems, that is at least equivalent, in terms of access to the system, to the other procedures for access referred to in this Chapter.
> 5. The operator of the transmission or distribution system concerned may refuse access where he lacks the necessary capacity. Duly substantiated reasons must be given for such refusal, in particular having regard to Article 3.

There is no definition of "published tariffs" in the Directive although Article 2 states that "'transmission` shall mean the transport of electricity on the high-voltage interconnected system with a view to its delivery to final customers or to distributors." Therefore the individual Member States have a great deal of freedom in deciding exactly how the cost of network access should be allocated among producers, suppliers, and end users and how the metering, billing, and settlement system should be arranged. The "published tariffs for the use of the transmission and distribution systems" might include:

- a tariff for revenues collected by the Transmission Asset Owner
- a tariff for revenues collected by the Transmission System Operator, if it is independent from the Transmission Asset Owner
- a tariff for certain revenues collected by the Market Operator, if the Market Operator is obligated to pay for network energy losses or ancillary services
- a tariff for revenues collected by a power exchange or any other entity that plays a vital role in ensuring "access" to the transmission and distribution system and covers access-related costs through published tariffs rather than market-determined prices.

All of these tariffs, taken together, may be defined as a *use-of-system tariff* in a particular country. The simplest example would be a tariff published by a Transmission Asset

Owner/System Operator that takes care of everything related to access to the transmission network.

If a power exchange manages transmission congestion via market splitting or if some other entity manages congestion through auctioning of cross-border transmission capacity, the prices determined by these entities are not part of the use-of-system tariff because they are not published tariffs.

3.4 Methods of recovering the cost of energy losses

There are three possible ways to recover the cost of transmission system losses:

(1) The use-of-system tariff includes a component that is used to recover the cost of transmission system losses. This tariff component may not precisely reflect the cost of losses but it should be designed so that the expected value of loss-related revenue is close to the expected value of loss-related expenses.

(2) The electricity market rules may specify that in any bilateral transaction between a supplier and a customer, the supplier must input to the transmission system more energy than the customer's offtake from the transmission system.[17] The additional input should be a specified percentage of the energy in kWh that is delivered to one or more offtake points for delivery to the customer.

(3) The electricity market rules could specify that any supplier or qualified customer who purchases power from a power exchange must purchase a larger quantity of energy than he receives from the exchange. The extra kWh purchased by the suppliers and qualified customers will be used to cover all of the network losses (transmission and distribution) involved in the delivery of energy to end users.

In practice option (3) is not implemented. Power exchange operators and settlement authorities typically do not want to know who are the end users of the energy traded at the wholesale market; they would rather let network owners recover the cost of network losses through use-of-system tariffs, and allow suppliers and traders to purchase and sell energy in the wholesale market without providing information about end users other than those who are wholesale market participants.

Let us examine the first option more closely. The use-of-system tariff is composed of one or more of the following types of charges:

(1) Fixed monthly charges and charges based on parameters that are not metered, such as transformer capacity or contractually guaranteed load in kW

[17] In some countries, such as Chile, market rules state that the producer who participates in a bilateral agreement must install more generating capacity than is needed by the consumer, so that the power system will have adequate capacity reserves. This practice is not common in Europe.

(2) Charges based on parameters that are metered, such as monthly energy consumption in kWh and annual peak load in kW, but unrelated to any transaction between the customer and a supplier

(3) Charges that are related to transactions between the customer and a supplier, such as payments that are made when the customer and the supplier are located in different tariff zones (geographic regions) and there is transmission congestion between the zones.

If the cost of transmission system losses are included in the tariff, these losses should be in category (2) because the true cost of losses is related to the customer's load profile rather than fixed parameters such as transformer capacity.

For Croatia it is definitely not a good idea to put transmission losses in category (3). DG TREN is strongly opposed to category (3) and seeks market-based mechanisms, such as transmission capacity auctions or spot markets with different spot prices in different zones, rather than zone-to-zone charges in the transmission tariff. Whether this pricing policy can be implemented in South Eastern Europe is still unclear. Because transmission energy losses in EHV and HV networks in Croatia are probably only 2 to 3 percent of energy delivered, there is no need to complicate the question of recovering energy losses in the tariff by getting into a discussion of transmission congestion management.

3.5 Energy losses and transmission tariffs in Western Europe

In western Europe there are four approaches to the recovery of energy losses:

- In Austria, Belgium, Denmark, Finland, France, Germany, the Netherlands, and Sweden, energy losses are included in the transmission tariff.

- In Norway and Spain the transmission system operator (TSO) is responsible for recovering the cost of losses, but the loss coefficients are not fixed. In Norway the TSO, Statnett, publishes marginal loss coefficients that are revised from time to time and vary by node of the transmission grid.[18] In Spain the TSO, RED Eléctrica, publishes marginal loss coefficients that vary by day and by node of the transmission grid.[19]

- In Italy, Ireland, and Portugal the transmission losses are the responsibility of generators. For example in Ireland the transmission system operator publishes Transmission Loss Adjustment Factors at www.eirgrid.com and generators are required to supply the additional energy specified in the table published by Eirgrid. Loss factors are calculated by the TSO and approved by the Commission on an annual basis.

- In England and Wales the market was originally designed on the basis of a mandatory power pool, and energy losses were included in the pool price. The new

[18] See http://home.statnett.no/tapssatser . These coefficients are published in Norwegian, not in English.

[19] See www.ree.es/apps/coeficientesingles.asp These coefficients are published in Spanish and English.

British Electricity Trading and Transmission Arrangements (BETTA) will establish a bilateral contract market and a voluntary power pool, but these arrangements are still under development.

3.6 Proposal for Croatia

The best solution for Croatia is to include the cost of transmission network losses in the transmission fee. The sophisticated approach used in Norway and Spain is too complex for the Croatian marketplace. From the standpoint of economic efficiency this approach use by Italy, Ireland, and Portugal does not appear to be very effective. The "true" cost of the energy represented by transmission system losses is revealed by a competitive spot market or by a balancing power market. On an annual basis these costs can be averaged and used to estimate the cost of transmission losses so that a tariff can be designed to recover those costs. No cost savings is likely to occur as a result of a policy that obligates the generator to provide additional energy to compensate for losses. In the absence of a competitive spot market or balance power market the "generators must cover losses" policy could result in a wasteful use of higher-cost generating units. Moreover, the approach used in England and Wales is suitable only for a mandatory power pool, and this situation is not applicable to Croatia.

3.7 Should the transmission loss component be time-differentiated?

We may observe, for example, that in Belgium the monthly charges for access to the system, in euro/kW/time period, are set for six different time periods:

- Winter peak hours (January through March, Monday - Friday, 0700-2200)
- Winter off-peak hours
- Winter weekend hours
- Summer peak hours (April through September, Monday - Friday, 0700-2200)
- Summer off-peak hours
- Summer weekend hours

Capacity access is cheap on summer weekend hours and expensive on winter peak hours. The tariff varies from 0.43 to 1.24 euro/kW/month for the first customer class and varies from 1.20 to 3.75 euro/kW/month for the fourth customer class. Transmission losses are included in the ancillary service charge, which is not time dependent and varies only very slightly, by customer class. The message to the network user is clear: the system is constrained by transmission capacity during the winter peak, but variations over time in the value of energy losses are not important.

Chapter 4 Identification and valuation of transmission assets

4.1 Separation of transmission, distribution, and generation

The formation of a transmission asset owner as a daughter company under a national holding company raises certain questions regarding the separation of Transmission from Distribution and from Generation. The following proposal has been developed on the basis of data provided by HEP Transmission:

400 kV transmission lines: All of these lines will always belong to HEP transmission. At 31.12.2001 there were 1157.4 km

220 kV transmission lines: All of these lines will always belong to HEP transmission. At 31.12.2001 there were 1245.1 km

110 kV transmission lines: A very small portion of these lines, 70 km, belonged to Distribution at 31.12.2001. To simplify the network tariffs it would be a good idea to transfer these assets to HEP Transmission, which owned 4762.6 km of 110 kV lines at 31.12.2001, and adopt a resolution that 110 kV lines should always belong to HEP transmission.

400/x kV transformer substations: Ownership at 31.12.2001 was divided between Transmission (2500 MVA, including 1600 MVA of 400/220 kV and 900 MVA of 400/110 kV) and Generation (300 MVA). To minimize the level of network tariffs it is best to keep those 300 MVA with Generation. However the Grid Code should clearly assign responsibility for ownership and operation of new transformer substations so that new generators know what they must build and pay for.

220/x kV transformer substations: Ownership at 31.12.2001 was divided between Transmission (2400 MVA) and Generation (750 MVA). To minimize the level of network tariffs it is best to keep those 750 MVA with Generation. However the Grid Code should clearly assign responsibility for ownership and operation of new transformer substations so that new generators know what they must build and pay for. If TS 1505/2 is replaced by a permanent switchyard, it should belong to HEP Transmission.

110/x kV transformers: Ownership at 31.12.2001 was divided between Transmission (4504 MVA), Distribution (1114.5 MVA), industrial consumers (851 MVA), Generation (476 MVA), and Croatia Railroad (232.5 MVA). [20] To minimize the level of network tariffs it is best to keep the 476 MVA with Generation. The Grid Code should clearly assign responsibility for ownership and operation of transformers connected to the 110 kV grid, so that market participants

[20] Total 110/x transformer substation capacity at 31.12.2001 was 7200 MVA:

4504 + 1114.5 + 851 + 476 + 232.5 + 22 = 7200 MVA.

HEP Transmission share is 4504/7200 = 62.5 %. The 22 MVA represents temporary capacity at TS 505.

know what they must build and pay for. It is not necessary to transfer ownership of existing 110/x transformers to Transmission, but it is necessary to define at least two customer categories: (1) customers receiving energy at 110 kV, who own their own transformers and (2) customers receiving energy at voltages lower than 110 kV, at transformers owned by HEP Transmission.

Medium voltage lines, 35, 20, 10 kV: Nearly all of these lines were owned by Distribution at 31.12.2001 but 57.8 km belonged to Transmission. To simplify the network tariffs it would be a good idea to transfer these assets to HEP Distribution, which owned 35637 km of medium voltage lines at 31.12.2001, and adopt a resolution that medium voltage lines should always belong to HEP Distribution.

Medium voltage transformers, 35(30)/10(20) kV: All of these transformers will always be owned by HEP Distribution

The definition of customer classes depends not only on the ownership of 110/x kV transformers but also the need for transit customers to have access to the 400 and 220 kV lines without using the 110 kV lines. Although electrons may flow freely in a 400/220/110 kV network it is not really "fair" to ask transit customers to pay for the 110 kV network unless they receive energy at delivery points on that network. This issue will be addressed in Task 3.

4.2 Valuation of assets owned by HEP Transmission

In the United States there is a widely-accepted principle of utility regulation which states that the customer should pay for *used and useful plant*, i.e. assets that are in operation and provide some benefit to the customer. There is also a principle that utility companies should purchase insurance against various hazards (fire, theft, and so forth) and the cost of this insurance should be borne by the customer.[21] However the United States has practically no experience in dealing with the question who should pay for the reconstruction of utility assets damaged by war. Obviously the Croatian transmission grid was damaged by war and someone has to pay for the reconstruction of transmission lines and transformer substations. If the assets of HEP Transmission will include only used and useful plant, the customer will not pay for war damage. If the assets of HEP transmission include both the original cost of damaged assets plus the cost of reconstruction, the result will be that the customer will have to pay for war damage.

At the beginning of 2002 the government of Croatia faced two policy alternatives:

a) Create a new company, HEP transmission, whose balance sheet does not include the original cost of assets damaged by war and does not include the liabilities associated with the original construction of those assets. Both the assets and the liabilities associated with those assets would be transferred to the Ministry of Economy or to some government agency. The value of assets on the balance sheet of HEP transmission at 31.12.2002 should be approximately equal to replacement cost less depreciation.

[21] There are statutory limits on the amount of liability the company has, and therefore the amount of insurance the company must purchase, in relation to damage caused by a nuclear reactor accident.

b) Create a new company, HEP transmission, whose balance sheet includes the original cost of assets damaged by war and includes the liabilities associated with the original construction of those assets. In other words the balance sheet shows the total investment in transmission assets, net of accumulated depreciation, and the total long-term liabilities associated with those assets. This involves "double counting" to cover the cost of reconstruction following war damage. Asset values could exceed replacement cost less depreciation, and could exceed the book value of comparable assets in countries without war damage.

For the purposes of this tariff study it is assumed that the Government of Croatia has chosen alternative (b). In other words we assume that the customers of HEP transmission (including transit customers) must pay for both the original cost of network assets plus the cost of rebuilding those assets. This government policy decision will raise the cost of electricity to everyone in Croatia and raise the cost of transit service to the transit customers who pay for access to the Croatian high voltage network.

Under ideal conditions (low inflation, high collection rates, and tariffs based on economic costs) the annual depreciation charge should reflect the true cost of replacing the assets that are being depreciated and therefore the customer must pay for the "true" cost of transmission service. Under these conditions the oldest lines and transformers in the transmission grid is constantly being replaced and the average age of transmission assets is influenced only by the growth rate of electricity demand. In central and eastern Europe, of course, these ideal conditions do not prevail; in many countries the transmission grid is "too old" because capital investments were deferred for several years. This problem is sometimes compounded by high inflation, and by accounting policies in which the book value of assets is not adjusted to compensate for inflation.

In Appendix 1, the table entitled *Valuation of the assets of HEP transmission at 31.12.2001* provides input data for the table of *Assets in service from 31.12.2001 to 31.12.2003* which in turn is used to calculate *Depreciation, 2002-2003.*

The "standard cost" data in the *Benchmark of Electricity Transmission Tariffs* study were submitted by energy regulatory authorities in response to the question, "Which is the typical total cost (€) of the following elements of the transmission network? 1 km of 400 kV line, 1 km of 220 kV line, etc." The responses are summarized below.

Standard costs of transmission assets

	€/Km of 400 kV line	€/Km of 220 kV line	€/Km of 132 kV line	€/Km of 66 kV line	€/MVA of transf. capacity
Denmark	400,000-600,000	400,000	200,000-300,000		
Finland	180,000	100,000	90,000	90,000	9,000
France[53]	460,000-610,000	275,000-460,000	155,000-230,000		13,000-15,000
Ireland	500,000	250,000	130,000		
Norway	265,000	157,000	120,000		18,000
Portugal	172,085	145,649	114,225		28,431
Spain[54]	239,263	141,358			7,452
Sweden	224,000	134,000			

Source: Ignacio Pérez-Arriaga et al, *Benchmark of Electricity Transmission Tariffs*, Prepared for the European Commission, DG TREN, February 2002, page 76.

4.3 Stranded costs

System peak load in 2001 was higher than in 1990, but annual energy consumption was lower in 2001 than in 1990. System peak load was 2421 MW in 1990, 2521 MW in 1991, 2023 MW in 1994, and 2796 MW in 2001. The sum of energy deliveries to the distribution network plus energy deliveries to consumers directly supplied by the transmission network plus transmission losses plus "other consumption" was 14.749 TWh in 1990, 12.920 TWh in 1991, 10.743 Twh in 1993, and 14.455 TWh in 2001. Apparently the system load factor decreased from 1990 to 2001 as a result of a decline in industrial load and an increase in consumption by households and small customers.

The change in the composition of customer load (away from the industrial sector and toward the household sector) has probably resulted in under-utilization of transformers 110/x originally installed to serve industrial customers. There could be a "surplus" of 110/x transformer capacity although HEP Transmission owns only 62.5 percent of 110/x kV transformer capacity in Croatia. In theory the customers of HEP Transmission would not have to pay for this surplus, if the value of HEP Transmission assets at 31.12.2002 excludes the cost of "surplus" 110/x transformer capacity that is no longer useful. However we assume that the customers will be forced to pay for "surplus" transmission capacity, if it exists, and we assume that the effect on the tariff is not very large.

Theoretically there could be a surplus of 400/x and 220/x substation capacity and a surplus of 400, 220, or 110 kV transmission line capacity on certain corridors. However the full cost of these assets should always be included in the transmission tariff, regardless of changes in load flow and monthly utilization, because the benefits are shared among countries and because it is nearly impossible to forecast the utilization of these assets over their physical lifetime (for example, 25 years). The 400 and 220 kV grid is in fact an

international grid that provides benefits to the entire south eastern portion of the UCTE first synchronous zone of operation. When HEP Transmission joins the European Transmission System Operators Association there will be an opportunity to participate in an inter-TSO compensation system, but at present there is no need to include an allowance for inter-TSO compensation in the transmission fee calculation.

4.4 Depreciation charges

Ideally, transmission fees should be stable from year to year. In real terms (that is, after adjusting for inflation), a transmission fee should not increase by 20 percent in one year or decrease by 20 percent in one year. To minimize the risk of prices increases it is a good idea to set a "correct" depreciation charge and not an artificially low depreciation charge.

We recommend that the depreciation lifetimes of all of the assets of HEP Transmission be reviewed to determine whether they are correct. The "correct" depreciation period for a particular transmission line or substation is the number of years that the asset is in service - the number of years until it is replaced or entirely rebuilt or taken out of service. From the customer's standpoint it would be beneficial for HEP transmission assets to have very long lifetimes – for example, 30 years – because the result would be a low depreciation charge. However, this is not realistic because the transmission networks of South Eastern Europe will need to adjust to changes in power system ownership and company structure, expansion of ETSO, implementation of the EU Electricity Directive, and changes in generation caused by changes in oil and gas prices and availability.

If assets are depreciated very slowly for accounting purposes (for example, over 30 years) but are in fact being replaced and rebuilt after 20 years, the result is that the annual depreciation charge will be too small and the value of assets on the balance sheet will be overstated. If asset values are not adjusted for inflation, the result is that the annual depreciation charge will be too small but the value of assets on the balance sheet will be understated. Having a "correct" balance sheet value is important when the shares are in private ownership, or privatization is planned, but it is not so important for companies that remain in state ownership.

Chapter 5 Definition of customer classes

5.1 Proposed definition of transmission customer classes

A *HEP transmission customer* is a legal person which receives energy from the HEP transmission grid, either supplies energy to the transmission grid or has made contractual arrangements for energy to be supplied to the transmission grid, and has a responsibility to pay a transmission fee.

When it is necessary to develop a definition of two or more transmission customer classes, two basic principles should be kept in mind:

1. The definition of the transmission customer classes should be simple.

2. Cross-subsidies should be avoided, if possible.

The following customer classes are proposed, on the basis of data received from HEP transmission:

1. **Delivery at 400 or 220 kV**: The transmission customer supplies energy to the transmission grid or makes contractual arrangements to supply energy at 400 or 220 kV, and receives energy at delivery points on the 400 or 220 kV network. These customers are transit or export customers.

2. **Delivery at 110 kV**: The transmission customer supplies energy to the transmission grid or makes contractual arrangements to supply energy at 400, 220, or 110 kV, and receives energy at delivery points on the 110 kV network. These customers own 110/x kV transformers.

3. **Delivery at 30, 20, 10 kV**: The transmission customer supplies energy to the transmission grid or makes contractual arrangements to supply energy at 400, 220, 110 kV, or medium voltage, and receives energy at 30, 20, or 10 kV from 110/x kV transformers owned by HEP Transmission.

To avoid cross-subsides the tariff for delivery at 400 or 220 kV should include costs related only to the assets needed to provide service to those customers; similarly, the tariff for delivery at 110 kV should include costs related only to the assets needed to provide service to those customers.

Chapter 6 Costs to be recovered through the transmission fee, ISMO charges, and balance power prices

6.1 Legal framework for system fees and charges in Croatia

On the basis of the Law on Electricity Market, the fees and charges for access to the system in a liberalized electricity market include three categories:

- *Electricity transmission fee.* This fee shall be set by the Energy Regulatory Council based upon the proposal of the energy undertaking carrying out transmission.[22] The fee will be set on the basis of a plan for development and construction of the transmission network for a 3-year period, and this plan shall be prepared by the System Operator in cooperation with the energy operator carrying out electricity transmission. The law does not say whether energy losses in the transmission network are included in this fee.

- *Electricity distribution fee.* This fee shall be set by the Energy Regulatory Council based upon the proposal of the energy undertaking carrying out distribution. The fee will be set on the basis of a plan for development and construction of the distribution network for a 3-year period, and this plan shall be prepared by the energy undertaking carrying out electricity distribution. The law does not say whether energy losses in the distribution network are included in this fee.

- *All other fees and charges* needed to enable the System Operator and the Market Operator to perform their duties, as defined in Articles 19 through 22 of the law. The Law on Electricity Market does not provide specific instructions about the way these fees and charges are established. The Energy Regulatory Council is responsible for "carrying out activities related to regulation of energy prices to be set on the basis of tariff systems."[23]

Therefore it is necessary to identify the way in which the development and construction programs will be financed, and the way in which transmission and distribution fees recover the cost of development and construction; identify the acceptable level of profit and the way in which profit should be included in these fees; decide whether energy losses should be included in the these fees; and identify all other fees and charges needed to enable the System Operator and the Market Operator to perform their duties.

Under the Law on Electricity Market, the Market Operator is responsible for establishing some kind of auction system involving competition among producers and importers:

> The Market Operator shall be responsible for: ...

[22] Law on Electricity Market passed by the Croatian Parliament on 19 July 2001, Article 12, paragraph (4).

[23] Law on Regulation of Energy Activities passed by the Croatian Parliament on 19 July 2001, Article 1, paragraph (1).

- collecting tenders and selecting the most successful tenders for meeting the demand for electricity in a specific period up to the moment when the demand is met, by ranking the tenders according to offered prices ...

- fixing final prices of electricity for specific time periods and informing energy undertakings participating in the market accordingly...[24]

In the light of western European experience it is reasonable to interpret Article 22 as a requirement that the Market Operator should establish a power exchange. In a power exchange, bids are submitted on the demand side (by suppliers and qualified customers) as well as on the supply side (by producers and importers).

The System Operator is responsible for the balance power market, among other things:

> The System Operator shall be responsible for:
>
> - operation and control of the electricity system,
> - ensuring access to third parties on the basis of regulated access
> - cooperation with energy undertakings carrying out transmission and distribution of electricity concerning determination and allocation of transmission costs,
> - providing services of the electricity system,
> - balancing supply and demand for electricity with respect to contracted quantities on the organized market, and issuing approvals for feasibility of short-term and long-term schedules...[25]

The System Operator could be the sole balance power provider, or could ensure that balance power providers can fulfil their commitments by participating in a power exchange. Although the option of using a power exchange to transfer balance responsibility to balance power providers is not mentioned in the law, this approach would be consistent with Nord Pool practice. The law does not obligate the System Operator to be the only balance power provider in the country.

6.2 Proposal prepared by the ISMO

Three different use of system charges are included in the proposal by the ISMO: an electric power system management charge, an electricity market organization charge, and a charge for regulating the energy industry.

[24] Law on Electricity Market passed by the Croatian Parliament on 19 July 2001, Article 22, paragraph (1).

[25] Law on Electricity Market passed by the Croatian Parliament on 19 July 2001, Article 20, paragraph (1).

6.3 Why balance power must be provided

The only way to maintain a stable frequency and voltage in a specific control area of an interconnected high-voltage network is to constantly maintain a balance between power flowing into the network from generating stations (or from neighboring networks) and power being taken from the network by consumers (i.e. system load). Somehow, the balance between generation and consumption must be maintained at all times while the market transactions are being implemented.

One solution is to establish a Balance Power Provider who will buy and sell kWh as needed to maintain a stable frequency and voltage throughout the control area, and recover the cost of this service by imposing a surcharge on the market participants responsible for causing the imbalance. The price of kWh bought and sold by the Balance Power Provider should vary from hour to hour (or at least, from month to month). The price is a "signal" to generators and consumers. When the balance power price is high, qualified customers and other purchasers should consider reducing their consumption, and should be careful not to consume more power than they have purchased through contracts with producers. When the balance power price is low, qualified customers and other purchasers should consider increasing their consumption, and should not worry about consuming more power than they have purchased through contracts. The problem cannot be solved by setting a fixed tariff, because that would destroy the "signal" and threaten the stability of the power system in a liberalized market.

A more sophisticated solution is to establish a spot market and require every market participant to settle his imbalances with a Balance Power Provider, or with the System Operator, subject to limitations that prevent small customers and small producers from settling directly with the System Operator. If hourly prices are set in a day-ahead spot market and a large share of total generation is sold at spot prices or under a formula based on spot prices, and if the control area has many buyers and sellers, then the spot market will help to maintain a balance between generation and load. Under these conditions the task of balancing generation and load in real time is much simpler, because the day-ahead schedule is already in balance and the spot prices provide an initial point of reference for balance power prices. Moreover, a few of the larger companies in the spot market may volunteer to become Balance Power Providers and offer their services to other participants, thereby eliminating the need for the System Operator to manage transactions with a large number of companies and keep track of all their imbalances.

If the System Operator had the ability to dispatch a hydroelectric station with a very large reservoir (or many hydro stations and many reservoirs) with a large and steady inflow from rivers, it would be possible for the SO to provide balancing services at very low cost – to balance generation and load in the control area by adjusting the level of hydroelectric generation. Under these ideal conditions the task of balancing generation and load would be simple, the cost of the service would be stable and predictable, and the cost could be included in the transmission tariff. In most control areas, of course, the solution is not so simple, and during peak periods or in "dry" years it is necessary to generate power using oil or natural gas (and using older, less efficient generating units). At these times the true cost of balance power is high.

6.4 Proposal for balance power pricing in Croatia

Although balance power pricing is the responsibility of the System Operator and not the energy undertaking carrying out transmission, it is appropriate for a study of transmission fees to identify the basic concept under which balance power will be provided. The Transmission Owner (TO) needs to provide market participants with access to the transmission network, but he cannot do this until a balance power pricing scheme is implemented under Article 20 of the Law on Electricity Market. The Transmission Owner would not have any role in balance power pricing.

6.5 Balance power providers in the Swedish electricity market [26]

Svenska Kraftnät's system responsibility entails planning and co-ordinating the national balance between the production and consumption of electricity, as well as overseas exchanges. The frequency of the system, which is a measure of its balance, must normally lie within a specific range around 50.0 Hz (±0.1 Hz). In order to be able to do this, Svenska Kraftnät has established a special function, the *balance service.*

The balance service must:

- maintain the country's electricity balance in a decentralised way via *balance regulation*
- distribute the costs of maintaining the balance between the players on the market via *balance settlement.*

A Balance Obligation Agreement has been signed by Svenska Kraftnät and about forty players, including the biggest producers. Players signing a Balance Obligation Agreement are called *balance providers.* They have undertaken to plan, on an hourly basis, for the production and purchasing of power to correspond to the expected consumption and sale vis-à-vis what they supply to their customers. Discrepancies in the balance are settled financially with Svenska Kraftnät afterwards. When required, Svenska Kraftnät can order regulation resources to be used when the frequency deviates from normal. These resources have been put at the disposal by balance providers by way of bids to Svenska Kraftnät.

Three levels of responsibility for the balance

There are three levels of responsibility for the balance on the Swedish electricity market (Fig 8). On the national level, Svenska Kraftnät is responsible for the balance of the entire electricity system, under the Electricity Act. This means that the balance service maintains the electricity balance between production and consumption on an instantaneous – or minute-by-minute - basis. The balance service also collaborates with similar functions in Norway, Finland and Denmark. By monitoring and, when required, correcting imbalances between the Nordic countries, the system operators can ensure that each country is doing its fair share of the necessary joint regulation work.

[26] This section is copied from *The Swedish Electricity Market and the Role of Svenska Kraftnät*, November 2001, pages 6-7. This document is published at www.svk.se .

The second level of responsibility consists of the balance providers, which are obligated under the Balance Obligation Agreement to maintain their company balances on an hourly basis.

On the third level of responsibility, we find the great majority of players - the electricity suppliers who supply electricity to consumers, or those who are consumers themselves. These players have not signed a Balance Obligation Agreement with Svenska Kraftnät, instead having to enter into an agreement with a balance provider who will then manage the balance on their behalf.

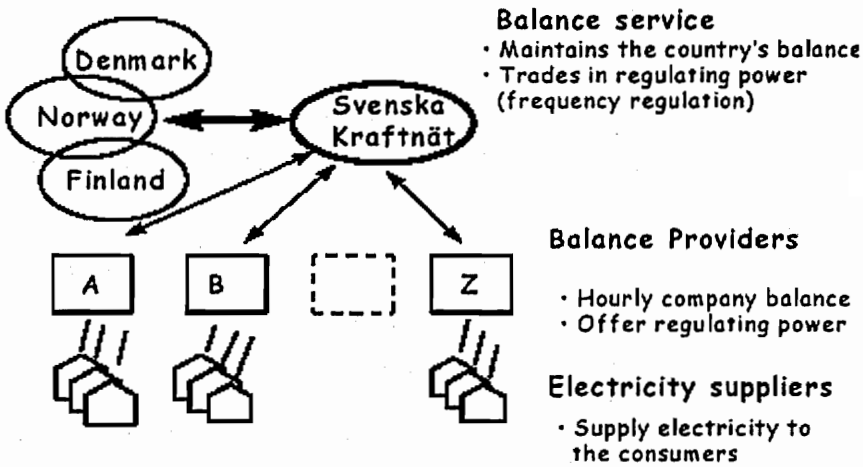

Fig 8. Three levels of responsibility for the electricity balance: The balance service at Svenska Kraftnät, the balance providers and the electricity suppliers.

A balance provider's imbalance is calculated each hour in three ways as shown in Figure 9 below. Firstly the planned imbalance is calculated by adding the reported (ex-ante) generation to any reported purchases (trade) and subtracting the forecast load and any reported sales (trade). This compares the companies' physical input to the physical output in the planning stage. Secondly the measured generation is subtracted from the generation plan. Finally the measured load is subtracted from the load forecast. These two comparisons check the quality of reported production and load forecasts, which can be changed right up to the start of the hour of delivery. The differences in these three calculations are settled as the purchase or sale of *balance power.*

Three company balances / hour

Reported (ex-ante)	Measured (ex-post)	Settlement
g) Generation plan	G) Measured generation	Balance power (generation) = G - g
l) Load forecast	L) Measured load	Balance power (load) = L - l
T) Trade	-------	-------
Settlement Balance power (planned) = g - l +/- T		

Fig 9. Example of company balances (per hour) with reference to planned and measured input and output of electricity.

Chapter 7 Valuation of Energy Losses in the HV Network

7.1 Quantity of electric energy losses

Transmission network input in 2001 was as follows:[27]

	Network input, GWh
Run-of-river hydro power stations	1396.2
Storage hydro power stations	4866.7
Conventional thermal power stations	4632.1
Import	3779.8
Total	14674.8

Transmission losses were 628.5 GWh or 4.3 percent of this total, for the EHV and HV network including most of the transformer capacity HV/MV. This percentage is high in comparison with France (2.5 percent) or Czech Republic (1.3 percent) although the transmission systems in those countries exclude transformer capacity HV/MV which is associated with additional losses of perhaps 0.6 percent. Technical factors affecting transmission losses vary from country to country. For example, the age and technical condition of the lines and transformers affect losses.

If HEP Transmission energy losses of 628.5 GWh in 2001 were valued at 22 Euro/MWh, the cost would be 102.3 million Kuna (assuming 7.4 Kuna per Euro). This is equivalent to 1.4 percent of the total operating expenditures of HEP in 2001 (7.339 billion Kuna)[28] so it must be only a small fraction of the cost of electricity to the consumer.

For the purpose of calculating a tariff, network losses may be described as a percentage of transmission network output. In accordance with current European practice it is appropriate to divide the electric energy output of the transmission network into four categories:

1. Electric energy delivered to transit customers and export customers at 400 or 220 kV

2. Electric energy delivered to domestic customers at 110 kV (that is, energy delivered to customers with a direct connection who own 110/x kV transformers)

3. Electric energy delivered to domestic customers at 30, 20, or 10 kV

4. Electric energy that passes through the network as a result of transactions in other countries, and is subject to an inter-TSO compensation system

[27] Hrvatska Elecktroprivreda Transmission Division, 2001 Report, diagram in section 8.

[28] Hrvatska Electroprivreda *Annual Report 2001*, income statement on page 29.

Let us assume, for simplicity, that category 4 was zero in 2001. Then category 1 was 587.8 GWh, categories 2 and 3 were 13458.5 GWh, and the total deliveries to customers were 14046.3 GWh. The annual cost of 139.5 million Kuna could be recovered by a transmission fee component of 0.99 lp/kWh.

7.2 Selecting a method of valuing energy losses

It is suggested that the following criteria should be used to select a method of valuing energy losses in the transmission or distribution network:

1. The method of valuing network energy losses should be simple.
2. The use of network fee should not reveal information about market prices. The Market Operator should be the primary source of information on market prices.
3. Cross-subsidies among customer classes should be avoided.

The simplest approach is to estimate the average value of transmission energy losses in 2003, in Kuna/MWh, multiply this figure by the projected quantity of losses, and divide by the projected energy deliveries to customers (including transit and export customers plus domestic customers). But how should the value in Kuna/MWh be measured? The best way to do this is to estimate the short run marginal cost (SRMC) of generation or imports in every hour of the year – for example, every hour of 2001 - and average all of the hourly figures. It is impossible to forecast electric energy prices in a future year, such as 2003, so it would be reasonable to estimate SRMC for an historical year, such as 2001.

The theoretically precise approach could be defined as follows:

1. In each hour, the economic value of electric energy losses at a particular node in the 400 kV network is the short run marginal cost (SRMC) of generation or imports supplied at 400 kV.
2. In each hour, the economic value of electric energy losses at a particular node in the 220 kV network is either (a) the SRMC of generation or imports supplied at 220 kV, or (b) the SRMC of generation or imports supplied at 400 kV plus losses in the 400 kV lines and 400/220 transformer substations, whichever is lower.
3. In each hour, the economic value of electric energy losses at a particular node in the 110 kV network is either (a) the SRMC of generation or imports supplied at 110 kV, or (b) the SRMC of generation or imports supplied at 220 kV plus losses in the 220 kV lines and 220/110 transformer substations, or (c) the SRMC of generation or imports supplied at 400 kV plus losses in the 400 kV lines and 400/110 transformer substations, whichever is lower.

Spain and Norway have transmission fees in which the loss calculation is very close to the theoretically precise approach.

Hrvatska Electroprivreda does not publish information about the marginal cost or average cost of different categories of electric generation and imports. However, dispatch curves provided by HEP Transmission show that there were only few off-peak hours during the year 2001 in which Croatia was a net exporter of electric energy (using hydropower to

export energy at night, in January and February 2001) and there were no hours in which hydropower supplies were large enough to eliminate the need for thermal power generation. Because Croatia was always a net importer of energy during peak hours, it is reasonable to guess that the off-peak exports in January and February were valued at some fraction of the price of energy imported during peak hours. Therefore in any hour of the year the SRMC of generation and imports must be either (a) the SRMC of thermal generation or (b) the SRMC of imports or (c) during off-peak hours in January and February, a fraction of the SRMC of imports.

Suppose that in each month of 2001 the price of energy imported by HEP from any import supplier was a fixed price per kWh for every kWh imported in that month. In each month, perhaps, the marginal supplier was the import supplier who charged the highest price per kWh in that month, and the SRMC of imports was the highest among import prices paid in that month. If imports are the marginal source of supply because there is not enough domestic generating capacity, the analysis of SRMC will be simple.

For Croatia in 2003 it will be necessary to have a financially strong transmission company but it might not be necessary to set a transmission fee based on the precise value of energy losses in the transmission network. For example, let's suppose that a value of 30 Euro/MWh is used to estimate the average SRMC, and the loss component of the transmission fee is 1.0 lp/kWh. If the actual cost of energy losses to HEP Transmission in 2003 is .9 lp/kWh then HEP Transmission will make a small "profit" on the energy loss component and this extra cash flow could put in a reserve fund to help pay for energy losses in the future. If the actual cost of energy losses to HEP Transmission in 2003 is 1.1 lp/kWh then HEP Transmission will make a small "loss" on the energy loss component but it should have an opportunity to increase the loss component to a higher value in 2004 (for example 1.2 lp/kWh) and offset the loss in 2003 with a small profit in 2004. Although this would not be a theoretically precise approach to the network energy loss component, it would be a simple and workable approach.

7.3 Terms of the agreement between HEP Transmission and its supplier

It is important to consider not only the loss component of the transmission fee, but the terms of the agreement between HEP Transmission and its supplier concerning payment for network energy losses. It would be financially harmful to HEP Transmission to have (a) a large and unanticipated increase in energy prices in 2003, and (b) an agreement with HEP Supply (or an agreement with the Market Operator) in which HEP Transmission must pay for network energy losses at market prices (for example auction prices), even if the transmission fee is based on a projection of SRMC of generation and imports and that projection is far below the level of actual market prices in 2003. If price risk is shifted to the supplier, the agreement will allow HEP Transmission to pay for losses at the price used to calculate the transmission fee. If price risk is shifted to HEP Transmission, the agreement will obligate HEP Transmission to pay for losses at auction prices or according to some price formula that is considered to reflect the market price, but HEP Transmission will not be allowed to increase the transmission fee. Obviously price risk can be shifted to HEP Transmission for only a limited time period (for example, up to one year) and then it will be necessary to adjust the transmission fee based on market conditions.

7.4 Time differentiation of losses

If the SRMC of generation and imports is significantly higher in winter than in summer, or significantly higher during peak hours than off-peak hours, then the transmission fee could have winter and summer values, or peak and off-peak values. However the price "signal" given by producers is always going to be much stronger than the price "signal" given by the energy loss component of the transmission fee. Arguably it is better to let bilateral contracts and spot markets send the correct price signals to producers and consumers, and not complicate the calculation of the transmission fee. Similar arguments can be made with regard to geographic differentiation of losses.

7.5 Valuation method used in the tariff calculation

To calculate a transmission fee for 2003, the following methodology was used in October 2002 to estimate the value of transmission system energy losses i.e. 22 €/MWh:

Deutsch

1. www.eex.de
2. Strom Spotmarkt: Ergebnisse Graf - Datum: [] - [OK]
3. Durchschnitt: 200 tage - [OK]
4. Graf: 1 monat
5. Druckansicht

English

1. www.eex.de/index_e.asp
2. Energy Spot Market: Trade Res. Graph - Date: [today] - [OK]
3. Average: 200 days - [OK]
4. Graph: 1 month
5. Printable version

Chapter 8 Transit fees in Europe

8.1 What is electricity transit?

The concept of *transit* originated in transport sectors in which tangible, physical products are shipped. In the energy sector for example, it is possible to define the *transit* with regard to crude oil, petroleum products, and natural gas. It is not very easy to define *transit* in the electric sector, even in situations in which it is obvious that the electric network is providing a service to buyers and sellers in neighboring countries.

Consider first a very simple example of transit: a crude oil pipeline which crosses a country and transports oil from a producing region to a refinery or port. Crude is produced in Country A and delivered to the border of Country B for onward shipment to Country C. In this example Country B receives crude oil of a certain quality and delivers this same quality of oil to Country C. There is no need for B to purchase the oil and resell it to C. The crude oil is not "mixed" in a pipeline network. In this example B is simply shipping a physical product from a receipt point to a delivery point. The owner of the crude oil pipeline in B has a right to charge a fee for the service of shipping crude oil from A to C. This is a transit fee. It should be calculated by estimating the cost of building and operating the pipeline within the national borders of B.

Next, consider a more complex example, in which natural gas is produced in various locations in Countries A, B, and C and processed and blended to meet certain quality specifications (for example, minimum and maximum heat content per thousand cubic meters). Suppose a gas producer in A has a contract to sell gas to a consumer in C, and the gas network of B lies between A and C. In this example we cannot trace the gas molecules that came from the producer's gas wells and see where they travel. Quite possibly none of these natural gas molecules are delivered to C. However, if the market value of a cubic meter of gas delivered to C is the same as the market value of a cubic meter of gas received from A, no one (except the dispatcher of the gas transportation system) really cares where the gas is flowing, because it is not their concern. The owner of the gas pipeline network in B has a right to charge a fee for the service of shipping natural gas from A to C. There are different ways to calculate the fee, but one possible approach would be to *pretend* that the gas travels along a certain route, and then estimate the cost of building and operating the facilities along that route, within the national borders of B. That route would be the *contract path*. If we compare a mathematical model of the gas network under two scenarios - Scenario I with gas receipts from the producer in A and gas deliveries to the consumer in C and Scenario II without those same receipts and deliveries - the difference between these two reveals the *physical path* of gas flow.

Next, consider an example in which electric energy is produced in various locations in countries A, B, and C and a producer in A has a contract to sell electric energy to a consumer in C, and all possible physical paths travel through B. In this example, we definitely do not want to trace the electrons that came from the producer's generating station and see where they travel. Practically speaking the grid is like a great big reservoir in which energy is received at some points and delivered at other points, and there is no reason to try to "label" the electrons as if they were goods to be shipped by truck or by rail. The electric energy is more valuable in some locations than in others. It flows according

to the laws of physics and its flow is not controlled by valves. The owner of the electric network in B could possibly have a right to charge a fee for the service of receiving energy from A and delivering it to C, but the question of "who should pay whom" is related to the timing of energy receipts and energy deliveries and to the full range of ancillary services provided by A, B, and/or C including frequency and voltage regulation, maintenance of hot reserves (spinning reserves), and so forth. Even when the electric energy is flowing from A to C, it is not clear who is getting the most benefit from the interconnection of A, B, and C. Perhaps there is very little physical flow across the borders, because producers in A sell to consumers in C while producers in C sell to consumers in A. The only thing that is clear is that the networks of A, B, and C are all experiencing energy losses. B's network cannot possibly receive energy from A and deliver it to C without incurring some sort of energy loss, so B has a right to ask for compensation for energy losses in its grid. In theory it would be appropriate to compare the actual level of losses (when transit occurred) against the theoretical level of losses that would have existed without any transit, and then compensate B for the difference. In practice a simpler approach is needed. Even if the producer in A and the consumer in C are willing to pay a "transit fee" to B, the amount does not necessarily reflect the incremental cost to B of providing network services needed to implement the bilateral contract between A and C.

Next, consider an example in which electric energy is produced in various locations in countries A, B, and C and a producer in A has a contract to sell electric energy to a consumer in C, but B contains two separate (asynchronous) networks. In this example energy is produced in A and consumed in B, in the first synchronous region, while energy is produced in B and consumed in C, in the second synchronous region. Since B enables the producer in A to sell energy to the consumer in C, it seems only fair that B should be compensated somehow. However, the electric energy does not flow from A to C. Can we say that B is entitled to charge a transit fee? Yes, but it would be difficult to estimate the incremental cost to B of implementing the bilateral contract between A and C. The *physical path* does not involve transit at all.

Even if all the countries are in one synchronous region, it is possible that the physical path does not involve transit at all. It is possible that the energy which is produced in A is consumed in the part of B that borders A, while the energy which is consumed in C is produced in the part of B that borders C.

Next, consider an example in which electric energy is produced in various locations in countries A, B, C, and D and a producer in A has a contract to sell electric energy to a consumer in C, but it is impossible to predict how much electricity will flow directly from A to C; how much will flow from A to B to C; and how much will flow from A to D to C. Can we say that B is entitled to charge a transit fee? No. Even if there exists a contract in which the *contract path* is from A to B to C, the *physical paths* are more complex. The most sensible arrangement would be to measure actual physical flows and develop some method of compensating the transmission companies for the incremental energy losses and the incremental cost of network services needed to implement all of the bilateral contracts in the marketplace, including the bilateral contract between A and C.

Finally, consider the example of an undersea cable connecting two asynchronous power systems using a back-to-back transformer on one side of the interconnection. The cable lies in the water *between* the two countries. If the two countries have different generation costs, electric energy should flow from the "least-cost peaking country" during peak hours

and should flow from the "least-cost base load country" during off-peak hours. The direction of flow could, in theory, change from hour to hour. Is this an example of electricity "transit?" No - this is cross-border trade, and it is something different. If the interconnection is under private ownership then the owner of the interconnection has a right to charge a fee for access to the transfer capacity. If the interconnection is under public ownership then its cost might be absorbed by national transmission system operators and recovered through use-of-network tariffs.

These examples show that electricity is a very special type of commodity – one which has some of the attributes of a *service* rather than a *good* – and therefore the concept of transit is difficult to define. The following definition was accepted by the Export-Import Working Group of the Energy Regulators Regional Association in December 2000:

> *Electricity transit* Scheduled flows of active power among three or more countries, based on an agreement in which at least one of the countries is neither an exporter nor an importer. The country which neither exports nor imports power, under the agreement, is a transit country and is compensated for making possible the physical flows of energy necessary for other countries to export or import power. Electricity transit is one form of *electricity trade*.[29]

This definition is based on the concept that if a producer in country A has an agreement to sell 100 MW to a consumer in C, while a producer in C has an agreement to sell 50 MW to a consumer in A, the net physical flow should be 50 MW from A to C. The consumer in A does not pay a transit fee and does not receive any "transit service." The consumer in C receives electricity from the grid but he does not pay a transit fee and he does not really care about the physical flow at all. Only the transmission system operators (TSOs) and independent system operators (ISOs) need to measure physical flows and therefore the system of compensation for transit must be established only among TSOs and ISOs.

In this context *export* and *import* should be measured on an hourly basis, or on even small increments such as 30 minutes or 15 minutes. Suppose, for example that electric energy is produced in various locations in countries A, B, and C and during peak hours A exports energy to B, but during off-peak hours B exports energy to C. A monthly total of hourly load flows will show that B is both an importer and an exporter. Should we consider B a transit country? No, because in any single hour B is either an exporter or an importer. A transit country delivers the same kind of energy (for example, peaking) that it receives.

The Electricity Directive (96/92/EC) does not define electricity transit at all. On 13 March 2001 the European Commission proposed a new Directive that would implement various amendments including the repeal of the two directives on transit that were published in 1990 and 1991. One of the points of the March 2001 proposal was the following recommendation:

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[29] ERRA, Export Import Working Group, *Electricity Trade and the Role of the Regulator*, Appendix A. Available from http://www.erranet.org/library/exim.htm . The final draft of this paper was accepted by the Working Group at a meeting in Bucharest, at the same time that ERRA was officially established.

> To ensure homogeneity in the treatment of access to the electricity and gas networks, also in the case of transit, Directives 90/547/EEC and 91/296/EEC should be repealed.[30]

In March 2001 the Commission proposed a Regulation containing the following definition:

> "Transit" of electricity means a physical flow of electricity hosted on the transmission system of a Member State, which was neither produced nor is destined for consumption in that Member State; this definition includes transit flows which are commonly denominated as "loop-flows" or "parallel flows".[31]

This definition is substantially the same as the definition adopted by the ERRA Export Import Working Group. Because the definition is based on physical flows, the only way to establish compensation for transit is to establish inter-TSO compensation. This definition is incompatible with any payment scheme in which the consumer pays a "transit fee" based on a contract path. The Commission correctly recognized a need to establish a system of inter-TSO compensation to address the problem of loop flows and parallel flows but the Commission did not define those terms.

8.2 Transmission tariffs in western Europe since March 2002

To eliminate pancaking and other problems involved in setting "transit fees" to be paid by either producers, traders, and consumers who have signed bilateral agreements, the European Transmission System Operators abolished transit fees entirely, with the approval of the European Commission and the Council of European Energy Regulators, effective 1 March 2002. In the ETSO press release dated March 7, 2002 the present tariff system is described as follows:

> The cross-border trade system, unanimously agreed by all Transmission System Operators (TSOs) in Europe in September 2001 under the presidency of André Merlin, was finally implemented on 1st March 2002 after overcoming remaining obstacles. Existing national export or import tariffs as well as the transit fees have disappeared. From last Friday on, market players do not need to pay in every system through which their transaction goes. Instead, they just pay once to the System Operator of the exporting country giving them right to use the entire European Continental network.
>
> The core of the CBT mechanism concerns the Continental power system of the EU including Switzerland. Austria, however, was not able to join the mechanism for the time being due to legal restrictions. Austrian TSOs should nevertheless be able to join as from April 1st, as announced by the Austrian Regulator at the 8th Florence Forum meeting on 21-22 February. Imports from other parts of ETSO area, that is

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[30] *Proposal for a Directive of the European Parliament and of the Council, amending Directives 96/92/EC and 98/30/EC concerning common rules for the internal market in electricity and natural gas*, paragraph (21) of the preamble. See http://www.europa.eu.int/comm/energy/en/internal-market/int-market.html .

[31] *Proposal for a Regulation of the European Parliament and of the Council, on conditions for access to the network for cross-border exchanges in electricity*, Article 2, paragraph 2(a). See http://www.europa.eu.int/comm/energy/en/internal-market/int-market.html .

Nordic, Greek, Slovenian, UK and Irish systems, also contribute to the Continental fund via an injection fee of 1€/MW to declared imports. This injection fee is paid once to the importing Continental TSO and gives also right to use the entire Continental network. This same injection fee will be required from declared imports originating in Morocco and Centrel countries.

As already explained, the purpose of ETSO solution is to secure that countries hosting transits caused by international electricity trade are compensated on the basis of measured physical flows for the service they offer. In this temporary mechanism the transit costs are recovered through two different means:

• Around 50% of the total costs through the national transmission tariffs of each country, so called socialization. Each country contributes to the fund proportionally to the net balance between exports and imports. And,

• around 50% of the total costs through a charge of 1 €/MWh from those responsible for export flows (traders or generators) for their declared exports and not for each individual transaction. Just 1 €/MWh will be paid whether the transaction goes from Spain to France or from Finland to Portugal.

This mechanism has increased transparency and fairness since all players are now treated equally. A meeting is organized by ETSO with market players on 5 March in Brussels to clarify some implementation details. It should be noted that this CBT mechanism does not include congestion management costs. Those costs are treated separately according to the systems in place for solving congestions in the different countries. The current CBT mechanism is of temporary nature. ETSO is preparing a more long-term system to be introduced in the beginning of 2003. [32]

In other words, western Europe is divided into three regions for transmission tariff purposes:

1. The Continental region, i.e. the western portion of UCTE consisting of EU countries (Spain, Portugal, France, Belgium Netherlands, Luxembourg, Germany, Austria, and part of Denmark) plus Switzerland. Here the traders or generators in each country pay the System Operator in that country a fee of 1 €/MWh for "declared exports" to other countries in the Continental region. This fee is similar to a "tax" on electricity exports, but the revenue is used to compensate TSOs for certain costs related to electricity trade.

2. Slovenia, Greece, the Nordel region, the United Kingdom, and Ireland. Here the market is liberalized according to the Electricity Directive and traders or generators pay a fee of 1 €/MWh for import into the Continental region. The fee is paid to the Continental TSO which receives the physical flow.

3. The other countries in the first synchronous region of UCTE including Poland, Czech Republic, Hungary, Slovak Republic, Croatia, Morocco, Romania, and

[32] European Transmission System Operators Association, press release, March 7, 2002. Posted at http://www.etso-net.org/frameset_3a.htm under "Press releases."

Bulgaria.[33] Here the electricity market is in various stages of liberalization and none of the TSOs is a full member of ETSO. For any physical flows into the Continental region, traders or "exporters" must pay a fee of 1 €/MWh to the Continental TSO which receives the physical flow.

The revenue collected from all of these 1 €/MWh fees plus a portion of the revenue collected from national transmission tariffs is put in a fund administered by ETSO and this fund is distributed among the ETSO members in the Continental region according to formulas agreed upon in September 2001.[34] In September 2001 the target level of revenue for this fund was set at 200 million Euro per year and the target date for implementation was 1 January 2002; this implementation was delayed for 2 months, however.

The tariff mechanism introduced in March 2002 was intended to be a temporary mechanism, to be replaced by a "permanent" mechanism in January 2003. When the temporary mechanism was proposed in September 2001 the European Commission was displeased with the fact that the national transmission tariffs have not been harmonized. Because 50 percent of the revenue collected under the temporary mechanism is being raised through the national transmission tariffs, the Commission is hoping for greater harmonization in the "permanent" mechanism. So far the new tariffs for 2003 have not been announced and it is reasonable to assume that these tariffs are still under negotiation.

[33] Romania and Bulgaria are very new UCTE members; they are still in a test phase and from time to time they could be outside the 1st synchronous region of UCTE.

[34] *ETSO proposal for a temporary CBT Mechanism*, 3 September 2001. Posted at www.etso-net.org .

8.3 Transmission tariffs that existed in Europe before March 2002

On 10 October 2001 ETSO issued a press release that summarized the pattern of transit fees in western Europe as follows:

COUNTRY	PRESENT			ETSO PROPOSAL
	Import Fee	Export Fee	Transit Fee	Export Fee
ES	None	from 1 to 3 €/MWh	= Export Fee	
FR	None	from 0.8 to 2.44 €/MWh	= Export Fee	
DE	0.64 €/MWh	0.64 €/MWh	1.2 €/MWh	
BE	None	1 €/MWh	1 or 1.5 €/MWh	
IT, NL, PT	None	None	None	
AT	None	0,808 €/MWh	Negotiated for each trader.	1€/MWh
CH			from 3,46 to 4,16 €/MWh	
LU	0.62 €/MWh	0.62 €/MWh	1.24 €/MWh	
DK	from 0.65 to 1,34 €/MWh (Eltra) None (Elkraft)	from 0.65 to 1,34 €/MWh (Eltra) 2 €/MWh (Elkraft)	= Exp./Imp. Fee = Export Fee	

Additional information on transmission tariffs existing in 2001 was published by the European Commission in a Staff Working Paper dated 3 December 2001. At that time it was reported that "a number of Member States currently have export and import charges in place as well as specific transit charges along the contracted path of any cross border transaction."[35] The following table was published on page 103 of the report.

[35] European Commission, *First benchmarking report on the implementation of the internal electricity and gas market*, Commission Staff Working Paper, SEC(2001)1957, Brussels, 3 December 2001 updated with Annexes: March 2002. See pages 103-104.

Table 3 Cross Border Transactions: Example Transactions

Connection	export/import charges (€/MWh)	transit charges
within Nordpool	import and export SV (2.00)	
Nord-DE	import DE (0.64),export DK (0.65-1.34)	N (check)
Nord-DE-NL	export DK (0.65-1.34)	DE (1.20)
DE-BE-NL	export DE (0.64), export BE (1.00)	na
FR-NL	export FR (0.8-2.44), export BE (1.0)	BE(1.0-1.5)
BE – UK	export BE (1.0)	FR (0.8 – 2.44)
DE-SP	export DE (0.64)	FR (0.8 – 2.44)
FR-DE	export FR(0.8 – 2.44), import DE(0.64)	na
DE/AT-CH-IT	export DE (0.64), export AT(0.81)	transit CH(3.46-4.16)

Source: ETSO, Nordel

It is important to recognize that the ETSO temporary tariff mechanism contains export charges, and there is nothing inherently "wrong" with export charges when the following conditions are observed:

1. The revenue collected from export charges is used to pay for infrastructure investments needed to make those exports possible.

2. The export charges are applied against physical flows, or against aggregated flows for each producer or trader

3. The export charges are only paid once, and there is no "pancaking."

On the other hand, transit charges based on *contract paths* are discriminatory, unrelated to costs, illogical, unreasonable, and probably also illegal from the viewpoint of the European Commission.

It would be possible to deal with transmission bottlenecks by setting area-to-area charges, which are export charges that vary according to the location of the purchaser or consumer. Although the European Commission does not want this approach to be implemented within the borders of the EU, it would be possible to set area-to-area charges in regions where there are not enough market participants to have a truly competitive auction or spot market.

Within the Nordel system there exist area-to-area charges for certain bilateral transactions in which the buyer and seller are located in different countries (an example of what ETSO refers to as "declared exports"). The overall policy goal of the member TSOs of Nordel is to reduce all of the cross-border charges to zero, for bilateral transactions within Nordel. However the development of the Nord Pool spot market reduces the importance of this issue, because a large portion of the net transfer capacity on each border is now used by Nord Pool rather than the bilateral contract market. There are no export charges, import charges, or cross-border fees for Nord Pool. Congestion is managed via market splitting.

8.4 Implications for HEP Transmission

To support the process of integration into the European electricity market, including electricity trade with Slovenia and Hungary, it would be best to assume that HEP Transmission will either become a member of ETSO or will participate in a system of inter-TSO compensation that will be very similar to the Cross Border Tariff mechanism implemented by ETSO. Therefore there is no reason for HEP Transmission to have any sort of transit fee for electricity transit across Croatia. It is reasonable to charge a transmission fee, including capacity and energy charges, for energy trading companies who have access the 400 kV and 220 kV network. The collection of these fees will become simpler when all of the countries neighboring Croatia have separated transmission activity from supply and trading activity, in accordance with the Electricity Directive. For neighbor countries that still have a vertically integrated power company, any request submitted to HEP Transmission to implement power flows related to trading and supply activity should be considered a request from a trading and supply "customer" rather than a request from a neighboring transmission system operator.

Chapter 9 Transmission fee components needed to cover capital investment needs

The expenses to be covered by the transmission fee should include depreciation and interest expense, which are normally included in a calculation of use of network fees for any transmission or distribution network owner. Depreciation may be viewed as a *return of capital* to the investor - in other words, it is a compensation payment reflecting the fact that long-term assets are getting older and becoming physically worn out and are therefore losing their value. Interest on long-term debt is one form of *return on capital* to the investor – in other words, it is an incentive needed to give companies and individuals a reason to save money and invest those savings in long-term loans.

Interest on short-term debt should be also included in the tariff calculation. This line item will not be very large, if the customers of HEP Transmission pay their bills on time. For this tariff calculation **an arbitrary value of 22.1** million Kuna is shown for 2003.

There is no need for HEP Transmission to earn a *return on equity*. Provided the quality of service is high, there is no need for the company to provide its "shareholder" with a return of capital invested. It is not important for HEP Transmission to pay dividends to the government of Croatia or to show increases in shareholder equity (retained earnings). If the capital expenditure program were small, it would be acceptable for shareholder equity to decline. On the other hand, a large capital expenditure program will require customers to make a contribution to HEP Transmission's equity capital though a surcharge (a "capital expenditure allowance") included in the transmission fee. There is no need to attract this investment by allowing a return on equity.

It is important to ensure that HEP Transmission will have enough cash flow to pay for the capital expenditure program and for principal payments on long-term debt. The transmission fee calculation is based on the following assumptions:

1. Depreciation is used to pay for capital expenditures for replacement and reconstruction of <u>existing</u> assets, plus principal payments on long-term debt

2. In 2003 there will be no principal payments on the 123 million Euro loan that was signed by HEP Group in 2002 to pay for the construction of the transformer station 400/110 kV Ernestinovo, the high voltage network related to Ernestinovo, and the transformer substation 400/220/110 kV Žerjavinec which is located near Zagreb.

3. To pay for the medium term investment plan in 2003, HEP Transmission should collect these funds by increasing the transmission fee. A special "capital expenditure allowance" should be included in the transmission fee. At present it is not appropriate for HEP Transmission to seek debt financing for the medium term investment plan, which involves **133,193,000** Kuna of capital expenditure in 2003 for <u>new</u> assets.

4. Debt financing for the medium term investment plan, which includes only new assets, might be considered in 2004 at the earliest. The sources and uses of funds for 2004 should be projected in the third quarter of 2003 so that a proposal can be developed concerning the level of transmission fees in 2004.

Page 4 of Appendix 1 shows a preliminary estimate of annual cash flow over the period January 1, 2002 through December 31, 2003 based on the assumption that there will be no debt financing for the medium term investment plan during this time period.

Chapter 10 Calculation of the transmission fee

10.1 General approach and procedure

To calculate a transmission fee it is necessary to:

1. Understand the objectives of the tariff-setting process, according to Croatian law (including the Law on Electricity Market and the Hrvatska Elektroprivreda d.d. Privatization Act) to answer questions such as:

    - How will capital expenditures be financed?
    - Should HEP Transmission earn a profit?
    - Should customers be allowed to receive transmission service, if they do not pay for it? Should any non-payment be allowed?
    - Should each customer group pay the "true" cost of transmission service or should a certain group receive a subsidy?

2. Propose guidelines for transmission fees, based on the EU Electricity Directive and western European experience, and answer questions such as:

    - Should the cost of electric energy losses be included in the transmission fee?
    - Should transmission customers pay a two-part fee or a one-part fee? Should there be a price per kW as well as a price per kWh?
    - Should power stations pay a transmission fee?
    - Should transit customers send payment in Kuna, as other customers do?
    - Should transmission fees be related to distance?

3. Develop a spreadsheet for the purpose of calculating the transmission fee.

    - Design the spreadsheet so that it will be easy to identify the input data, revise the input numbers, and re-calculate the transmission fee.
    - Use *actual* data wherever possible, and not hypothetical values. Collect data and calculate depreciation and other tariff components while the spreadsheet is being developed.
    - Try to forecast the financial health of the company under a given a set of assumptions about demand growth, spot market prices of electric energy, exchange rates, interest rates on long term loans, and so forth. Forecast depreciation, operating expenses, and cash flow.

In other words the key task is to determine what costs should be recovered through the transmission fee, and estimate the fee as accurately as possible while recognizing that some of the figures must be estimated because HEP Group is being restructured. The question of the final customer's ability to pay is not included in this analysis because the transmission fee represents only a small portion of the average cost per kWh of electric energy delivered to final customers, including households. It would not make sense to try to analyze a customer's "ability to pay" for transmission service received at 400 kV, 220 kV, 110 kV, or even at medium voltage. Distribution networks on the islands are connected to the national grid. Therefore the customer who is unwilling or unable to pay for transmission service will need to generate his own electricity or construct a direct line to a power station, and we assume that in Croatia the number of such customers is small.

A detailed list of the steps involved in this work is presented in the *Work Plan: Transmission Network Fees for Croatia* which is contained in the Appendices to this report. The Work Plan has been amended several times during the course of the project; it was initially drafted in May, discussed in Zagreb in June, and discussed again in September.

10.2 Structure of the transmission fee

The "reference case" for this tariff study is the transmission fee structure published by the Belgian transmission system operator at www.elia.be / grid access / tariffs. The Elia customer is offered a choice between a subscription period of one year and a subscription period of one month. For HEP Transmission in 2003 we recommend that all customers should have a subscription period of one year; this results in a simpler and more transparent tariff system. The option of one-month subscriptions to transmission service is a tariff refinement that could be offered in 2004 or later.

The Elia transmission fee is a two-part fee consisting of a capacity payment in Euro/kW per year and an energy payment in Euro/Mwh. Elia participates in the inter-TSO compensation system managed by UCTE, in which transit fees are prohibited. The Elia tariffs do not cover energy transit between two or more countries in the European electricity market over the Elia network. In the Elia system there are four different customer classes, and each customer class has a different capacity payment:

Subscription for a period of one year	Euro/kW per year
On the 380/220/150-kV network	25
At transformer output to the 70/36/30-kV network	40
On the 70/36/30-kV network	60
At transformer output to medium voltage	70

Although the energy charge varies by customer class, the ratio of the lowest energy charge to the highest energy charge is 0.927 and therefore the fee structure is very similar to a fee structure with a uniform energy charge to all customers. For HEP Transmission we

propose a uniform energy charge to all consumers. In fact the operation of EHV and HV networks is interrelated and it would be difficult to show that one group of customers is actually causing a higher percentage of energy losses than another group of customers. For Elia the energy charge covers not only energy losses but ancillary services. For HEP Transmission the energy charge should simply cover energy losses.[36]

For the HEP Transmission system we propose three customer classes

4. **Delivery at 400 or 220 kV**: The transmission customer supplies energy to the transmission grid or makes contractual arrangements to supply energy at 400 or 220 kV, and receives energy at delivery points on the 400 or 220 kV network. These customers are transit or export customers.

5. **Delivery at 110 kV**: The transmission customer supplies energy to the transmission grid or makes contractual arrangements to supply energy at 400, 220, or 110 kV, and receives energy at delivery points on the 110 kV network. These customers own 110/x kV transformers.

6. **Delivery at 30, 20, 10 kV**: The transmission customer supplies energy to the transmission grid or makes contractual arrangements to supply energy at 400, 220, 110 kV, or medium voltage, and receives energy at 30, 20, or 10 kV from 110/x kV transformers owned by HEP Transmission.

The Elia transmission fees do not cover the cost of new connections to the grid, or work on existing connections. We assume that the same rule applies to HEP Transmission, although a detailed Grid Code was not available for this tariff study. The HEP Transmission tariffs cover the repair and replacement of existing transmission facilities, the construction of the transformer station 400/110 kV Ernestinovo, the high voltage network related to Ernestinovo, the transformer substation 400/220/110 kV Žerjavinec, and new facilities in the medium term investment plan.

In Belgium, France, Germany, and Spain the transmission fees are paid by customers and not by producers. We propose that HEP Transmission should follow this example.

10.3 Import, export, and transit

A difficult question for any transmission system is the question of how to charge fees for import, export, and transit. This is not a "national" issue because the solution must be found in the form of a compromise among the interests of various neighbor countries, each of whom receives certain benefits and incurs certain costs related to the synchronous operation of the interconnected EHV and HV networks. Although the EU Electricity Directive establishes guidelines for the separation of production, transmission, and distribution activities at the national level it is silent on the question of how to conduct electricity trade at the border between two countries when there is an unbundled power sector on one side and a vertically integrated power company on the other side.

[36] Possibly the energy charge could also include incentive payments, which are explained in Chapter 11.

At the ninth meeting of the European Electricity Regulatory Forum, which was held in Rome on 17-18 October 2002,[37] there was a discussion of the *ETSO proposal for a 2003 CBT Mechanism* which proposes certain changes to the existing cross-border tarification[38] mechanism introduced 1 March 2002.[39] According to the proposal "ETSO will be able to apply this method from January 1st 2003 providing the endorsement by the concerned regulatory bodies and the European Commission in due time." A two-page press release was posted 15 October 2002, summarizing the CBT proposal.

The paper presents a methodology for identifying the portion of the European transmission network for which costs should be shared, under an inter-TSO compensation mechanism. The proposal is that cost sharing should be applied only to those facilities in a particular TSO network that would be needed to support 100 MW of "one-to-one" transit flows, i.e., the simultaneous receipt of 100 MW and delivery of 100 MW at two different border points. This is a "technical auditable approach" which can be initially implemented by "comparing an empty network with superimposed transits" and later improved through the collection and analysis of hourly flow data for the UCTE area. The facilities needed to support the 100 MW transit flows are defined as the *horizontal network*. The draft Conclusions of the European Electricity Regulatory Forum noted that "the definition of the network affected by transits is more robust" but "further information on the proposal was necessary, particularly with regard to regulated costs."[40]

It is reasonable to assume that the 400 kV and 220 kV network of Croatia is part of the *horizontal network* to be defined by ETSO. The costs of the horizontal network in Croatia should be shared with the TSOs in Slovenia, Hungary, and western Europe. Although HEP Transmission is not a member of ETSO, ELES (Slovenia) is a member of ETSO and MVM (Hungary) is an associate member. It is reasonable to assume that HEP Transmission will become an associate member of ETSO during the next two years. Therefore any HEP Transmission fee for export, import, or transit should be considered a temporary measure that will be eliminated or at least substantially changed after HEP Transmission joins ETSO.

At present there is no clear consensus of the European Electricity Regulatory Forum regarding the precise method of harmonizing transmission fees in the EU countries,

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[37] The relevant documents will most likely be posted by the European Commission, DG TREN at http://www.europa.eu.int/comm/energy/en/elec_single_market/florence/index_en.html . The agenda and conclusions will most likely be posted at http://www.ceer-eu.org / click on "Public Documents / click on "Florence Forum." A few documents were posted at www.etso-net.org in advance of the Forum.

[38] "Cross-border flow" means the physical flow of electricity across the borders of Member States and across the borders of control blocks operated by transmission system operators. If a country has only one transmission system operator (TSO), cross-border flow is measured at the borders of the country. Some countries (e.g. Germany) have two or more TSOs and each TSO has a control block. See *ETSO proposals for definitions to the current proposal for a Regulation of the European Parliament and of the Council on conditions for access to the network for cross-border exchanges in electricity*, 14 October 2002.

[39] On 14 October 2002 the European Transmission System Operators Association (ETSO) posted at www.etso-net.org two papers dated 11 October for discussion on 17-18 October.

[40] *Conclusions: Ninth Meeting of the European Electricity Regulatory Forum, Rome, 17-18 October 2002.* Distributed on 25 October 2002.

Norway, and Switzerland. – for example, eliminating transmission charges to producers. Moreover there is no consensus regarding "who pays whom" for the horizontal network. There are several possibilities, for example:

- The TSOs which import power to serve the needs of final consumers must pay compensation to the TSOs located in countries where the power was produced, and the TSOs who provided transit service including loop flows. OR
- On a monthly basis each TSO is entitled to compensation for total imports or total exports, whichever is larger. (This is the status quo.)

Each European power system is designed to ensure that during the annual peak hour (typically the winter peak) the available generating capacity in MW plus firm peak imports in MW will be enough to cover domestic consumption in MW plus network losses plus a target reserve margin, in percent.[41] If the transmission system must also guarantee the ability to provide transmission capacity needed to export power at the winter peak or provide transit service at the winter peak, it is logical to expect the TSO to ask someone to pay for that peak capacity. In the simplest case, all transmission costs would be charged to loads (L), nothing at all would be charged to generators (G), and the cost of the horizontal network would be multiplied by an "export key" – the share of peak capacity in MW that used to support electricity export (including power that is imported for the purpose of serving an export customer). In fact each TSO's guarantee of peak capacity would be backed up by a contract.

The true costs of the transmission network are related to physical flows of energy rather than contract paths. The best way to develop a cost-based transmission fee for customers at 440 and 220 kV is to calculate the capacity payment per kW per month and the energy charge per kWh on the basis of physical flows. Of course, this means that the total physical flow must be broken down into components so that the flow at each import point and each export point is allocated to certain customers. This is not too difficult to do, when the number of customers is small, and the tariff calculation is based on simple assumptions for each neighbor country.

We shall assume that during the transitional period before ETSO membership HEP Transmission should apply a transmission fee to exports, but not to imports, and the capacity fee should be applied to peak capacity in MW. Both a capacity fee and an energy fee should be charged for exports on the basis of physical flows. There is no need to define "transit" or establish a "transit fee." We assume that entities in Austria, Italy, Germany and other countries will not make payments to HEP Transmission (before ETSO membership) and that loop flows are not reflected in the forecast of peak flows in 2003.

Long-term contracts are the best guarantee of transmission fee revenue from entities located in neighboring countries. Some sort of agreement would be necessary to prevent "cheating" e.g. to prevent a situation in which a neighbor country asks HEP Transmission to invest in the transmission facilities needed to guarantee a reliable supply of energy at the annual system peak, and imports electricity during peak periods, but does not import

[41] In the UCTE data, network energy losses are included in "domestic consumption" although of course this energy never reaches the consumer.

energy during the one hour corresponding to Croatia's annual system peak load. The System Operators and TSOs of Hungary, Slovenia, Bosnia-Herzegovina and Croatia should develop an "accounting system" to allocate peak cross-border flows among the customers who must be invoiced by HEP Transmission and by neighboring transmission companies.

10.4 Transition to the two-part fee

The structure of fees for the various HEP affiliate companies in an unbundled and competitive electricity market is probably going to be subject to widespread discussion and debate. For the average citizen the issue of international electricity trade is confusing, and it is easier to think of HEP as a company that serves customers in Croatia and collects all of its revenue from Croatians. Moreover for the average citizen the idea of a two-part transmission fee is confusing; it is easier to think of transmission fees measured in lp/kWh only.

Let us suppose, therefore, that at the beginning of 2003 the transmission fee will be extremely simple and HEP Transmission will have only one category of customer:

- **Delivery at 110, 30, 20, 10 kV**: The transmission customer supplies energy to the transmission grid or makes contractual arrangements to supply energy at 400, 220, 110 kV, or medium voltage and receives energy at delivery points on the 110 kV network or at 30, 20, or 10 kV from 110/x kV transformers owned by HEP Transmission.

Furthermore let us suppose that the fee will consist of a price in lp/kWh. Although this is not the ideal solution from a technical perspective, it is easy to explain to the customer.

10.5 Calculated results

The two-part transmission fee structure is as follows:

Type of fee	Customer class	Calculated value	Monthly revenue, million Kuna	Annual revenue, million Kuna
Capacity	Delivery at 400 or 220 kV	**7.62** Kuna/ kW/ month	**0.762**	
Capacity	Delivery at 110 kV	**15.62** Kuna/ kW/ month	**10.581**	
Capacity	Delivery at 30, 20, 10 kV	**21.84** Kuna/ kW/ month	**49.206**	
Capacity	All customers		60.549	726.591
Energy	All customers	**0.77** lp/kWh		119.941
Total	All customers			846.532

Source: Appendix A, Excel spreadsheet file *sample HEP transmission fee for 2003.xls*

The one-part transmission fee structure for the beginning of 2003 is as follows:

Type of fee	Customer class	Calculated value	Monthly revenue, million Kuna	Annual revenue, million Kuna
Energy	All customers	5.82 lp/kWh		846.532

Source: Appendix A, Excel spreadsheet file *sample HEP transmission fee for 2003.xls*

Chapter 11 Incentive regulation

This chapter discusses the potential incentives that could be included in HEP Transmission's fee structure. Given the functions of HEP Transmission and the provisions of Croatian energy laws, there exists only a limited possibility to include such incentives. Some flexibility appears to exist, however. It should be possible to allow the salary structures to be tied to performance.

11.1 HEP Transmission Functions

The analysis of the question of what sort of performance targets can be included in HEP Transmission's fee structure begins with identifying what task HEP Transmission performs in the restructured energy market.

The main task of HEP Transmission is to construct transmission networks and maintain them in good condition to ensure a reliable supply of electricity to the distribution networks, to large customers with direct connections to the transmission network, and to transit customers. It is a combination of (a) a construction company and (b) a service provider responsible for maintaining the transmission network in good technical condition.

In other words HEP Transmission is very different from the companies that own transmission facilities in the United States. It is neither System Operator nor Market Operator. It is not responsible for dispatch or transit, nor is it responsible for designing the transmission network with a view to eliminate transmission congestion. The concept might be explained in the following terms:

- If HEP Group were an airport operator, the task of HEP Transmission would be to build airports and maintain them to ensure that control towers and equipment are reliable and safe and to ensure that there is a very low probability that the airport will ever need to be shut down as a result of equipment failures.

- If HEP Group were a bridge operator, the task of HEP Transmission would be to build bridges and maintain them to ensure the safety of car and truck traffic.

- If HEP Group were a tram system operator, the task of HEP Transmission would be to build tram tracks and cars and maintain them to ensure passenger safety and to minimize the risk of delays associated with the condition of tracks and cars.

- If HEP Group were an airline, the task of HEP Transmission would be to build airplanes and maintain them to ensure passenger safety and minimize the probability of flight delays associated with the technical condition of the airplanes.

Contracts to build high-voltage power lines, airports, bridges, or tram systems can be awarded on the basis of competitive bidding. Therefore in theory this kind of construction/maintenance company could be established as a competitive business operating in many countries around the world, rather than a monopoly operating in one country. However, HEP Transmission is a national, government-owned monopoly. It does not earn profits and does not compete for business. If we look for this type of

organization in the United States at the national level, no analogous examples come to mind, although HEP Transmission could be viewed as somewhat similar to the Army Corps of Engineers (and the government-owned shipyards that operated during World War II).

11.2 Distinguishing the "owner" from the "operator"

Given HEP Transmission's functions as described above, the company will need to establish a close working relationship with the ISMO - the entity that will be performing many functions that affect the day to day operation of transmission system assets. According to Article 29 paragraph (5) of the Electricity Market Law, HEP shall found "the share-based company that will operate the Croatian electricity system and organization of the electricity market" i.e. the ISMO as a state-owned company. From the standpoint of the customer who receives transmission service it is important to know which entity will sign a contract to provide service. That obligation to serve the customer should be reflected in the license conditions. The license conditions, in turn, provide a basis for measuring performance and possibly setting up a regulatory framework with rewards for good performance and penalties for poor performance.

Normally, if the *asset owner* is not the same entity as the *operator* of a business, the two parties contract under a lease agreement in which the asset owner transfers rights to the operator, including the right to contract with customers and collect payment from customers. Alternatively there could be a concession agreement in which the operator is given greater freedom to modify the assets or take the older assets out of service; from the customer's point of view this is nearly the same as a lease agreement.

The Electricity Market Law does not say which entity should sign contracts with transmission service customers, and does not define precisely who is the owner of the transmission system. Ultimately, it is possible to imagine any of the following ownership arrangements, within the general framework of the Electricity Market Law:

1. *HEP Group ownership.* In this variant the transmission system assets are owned by HEP Group, which issues a lease to the System Operator, defining the services to be provided to customers. HEP Group and the System Operator would then sign contracts with transmission customers.

2. *HEP Transmission ownership.* In this variant the transmission system assets are owned by HEP Transmission, which issues a lease to the System Operator, defining the services to be provided to customers. HEP Transmission and the System Operator would then sign contracts with transmission customers.

3. *Government ownership.* In this variant the transmission system assets are owned by the Ministry of Economy, which gives instructions to HEP Transmission concerning development plans, construction projects, and technical operating standards.[42] The Ministry issues a Lease to the System Operator, defining the services to be provided to

[42] Under the HEP d.d. Privatization Act, the Government of the Republic of Croatia exercises a great deal of ownership control and the possibility of government ownership of the transmission sector is not excluded.

customers. The System Operator would then sign contracts with transmission service customers.[43]

If we knew precisely what the standard customer contract will say, and who signs the contracts, then it would be easier to define the license conditions for HEP Transmission. The Law on Electricity does not say who will own the assets, however, so it is difficult at this point to define these conditions precisely.

Unless a substantial portion of HEP Transmission's service group will be transferred to the ISMO, it may make sense during an initial transitional period for the ISMO to contract with HEP Transmission to perform some of the operating functions that are the responsibility of the ISMO according to the Electricity Market Law. Similarly, it may make sense for the customer to sign contracts initially with both HEP Transmission and the ISMO to clarify exactly who is responsible for what, during the transitional period. At a later stage in electricity market development it may be possible for the System Operator to take charge of all contract negotiations affecting third party access to the network and take all responsibility for relations with customers.

Article 10 of the Law on Electricity Market also includes the word "operator", which leads to some ambiguity, given that the System Operator and Market Operator appears to be required to do everything that "operators" normally do. The precise wording of Article 10 paragraph (1) is as follows:

Article 10

(1) The energy undertaking carrying out transmission of electricity shall be responsible for the construction, operation and maintenance of the transmission network, and the generation of a portion of reactive power.

In addition, the second paragraph of Article 18 authorizes the transmission undertaking to sign contracts with customers but does not require the System Operator to sign contracts with customers:

Article 18

(1) Supply of electricity to eligible customers is the activity where eligible customers and electricity suppliers freely negotiate the quantity and price of electricity that is the subject of delivery.

(2) Electricity suppliers and eligible customers shall submit the contracts from point (1) of this Article, as well as the contracts concluded with the electricity transmission undertaking and/or distributor to the Market Operator.

The standard contract between the electricity transmission undertaking and its customer might say that the customer is obligated to do three things:

- Pay the transmission fee

[43] Arguably this approach may be a violation of Article 18, paragraph (2) which refers to "contracts concluded with the electricity transmission undertaking" but Article 20 does not prohibit the System Operator from signing contracts with customers.

- Obey the Grid Code described in Article 16
- Obey the Rules for connections, described in Article 5.

Because the use-of-network services are typically the responsibility of the System Operator and the Market Operator, however, it is not clear what kind of "market access" the electricity transmission undertaking can offer the customer in exchange for the transmission fee.[44]

In sum, the precise parameters of HEP Transmission's duties will need to be fleshed out in the Market Rules and Grid Code, which makes identification of performance targets at this time more challenging. At this point, those duties appear to be at least the construction and maintenance obligations noted above. It may also be useful during the initial phase of market opening for HEP Transmission to perform, under contract, some of the tasks which the Electricity Market Law assigns to the ISMO.

11.3 Absence of a profit motive

Another factor influencing what sort of performance targets can be included in any fee structure is HEP Transmission's non-profit status.

Nothing in the Electricity Law suggests that HEP Transmission should earn a profit. Therefore a surplus of revenue over expenses can be used to invest in improvements to the transmission network, or can be returned to the customer by reducing the transmission fee. Similarly a deficit of revenue over expenses will force the company to delay improvements to the transmission network, unless additional revenue is collected from the customer by increasing the transmission fee. The shareholder (either the Government of Croatia, or HEP d.d.) is not interested in earning a "profit" from this business.

This means that imposition of the fines listed in Article 28 of the Electricity Market Law would probably not be productive if applied to the transmission undertaking as a whole (as opposed to individual directors, officers or employees.) Let us assume for example that the revenues of the transmission undertaking will be 846,000,000 Kuna in 2003. In that case total revenue would be 84,600 times larger than a 10,000 Kuna fine:

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[44] The Electricity Market Law does not specifically require the transmission undertaking to invest in connections to new energy undertakings and customers, or build those connections:

Article 5

(1) Costs of connection of new energy undertakings and customers to the network as well as costs related to the transmission or distribution network that may arise as a result of such connection, shall be borne by the applicant for connection to network and by other network users that may have benefit from such connection, in accordance with the Grid Code.

(2) Conditions and the manner of calculating connecting costs and their distribution on users that benefit from such connection shall be regulated by the Rules to be passed by the Minister.

The question who pays and who builds, therefore, should be clarified in the objective and non-discriminatory Market Rules, consistent with Article 7, paragraph 2 of the Electricity Directive which requires that "Member states shall ensure that technical rules establishing the minimum technical design and operating requirements for the connection to the system of generating installations, distribution systems, directly connected consumers' equipment, interconnector circuits and direct lines are developed and published."

Article 28

(1) A cash fine ranging from HRK 10,000.00 to 50,000.00 shall be imposed on an energy undertaking that:

- fails to maintain the transmission network (Article 10, point (1)),
- fails to proceed in accordance with Article 10, point (2) hereof,
  ...
- fails to prepare plans for development and construction (Article 12, point (1)),
- does not prepare development and construction plans in compliance with the Energy Strategy and Strategy Implementation Program (Article 12, point (3)),
  ...
- does not apply the Grid Code (Article 16),[45]
  ...

In other words, the penalty could be too small to influence conduct.

Similarly, according to Article 18 of the Energy Law, an energy undertaking that receives a license for transmission of electricity could have its license cancelled. There is no indication, however, that the ownership of transmission system assets could be changed by the license provisions. As a result, the Energy Regulatory Council might not be able to effectively discipline HEP Transmission by threatening to cancel the license. (Indeed, as a practical matter, there may not be any other entity able to perform those licensed functions.)

Two responsibilities of the transmission undertaking are not subject to a fine under Article 28, but are tasks that the entity would want to perform in any case:

- to propose a transmission fee, according to Article 12 paragraph (4)
- to cooperate with the System Operator concerning the determination and allocation of transmission costs, according to Article 20 paragraph (1).

The Law on Electricity Market does not contain provisions that may be used to reward the management of HEP Transmission for superior performance. It does contain provisions, however, that may be used to penalize the management of HEP Transmission for poor performance:

(2) A cash fine ranging from HRK 2,000.00 to 10,000.00 shall be imposed on a responsible official of energy undertaking for offences laid out in point (1) above.

Such penalties, however, are imposed by the prosecutor, not the regulator, and so also do not appear to be an effective avenue for CERC to influence behavior.

[45] According to Article 20 paragraph (1) the transmission undertaking should follow instructions from the System Operator concerning operating criteria related to reliability and security in line with the Grid Code.

11.4 Regulatory incentives

The environment noted above shows two things: (1) defining performance targets in the fee structure will be a challenge, but (2) is important in order to give CERC some mechanism to influence licensee conduct.

So let us return to the main task of HEP Transmission defined by Article 10: to be responsible for the construction and maintenance of the transmission network. What does good performance look like? What does bad performance look like? How could CERC reward good performance and penalize bad performance, through the tariff-setting process?

The main indicators of good performance would be:

- Completion of major construction projects ahead of schedule or under budget.
- Maintenance of a good safety record on all construction projects; avoidance of accidents.
- Achievement of high rankings in a benchmarking study, when European transmission companies are ranked according to indicators of continuity of supply

Given the legal framework noted above, the most effective way to reward good performance through the fee-setting process is to set specific targets for "Salaries and related expenses" and allow this line item to be increased by a certain percentage, based on good performance, for a period of no less than one calendar quarter. Additional transmission revenue could be collected by increasing the level of the energy charge per kWh (for example, the proposed 0.62 lp/kWh charge in a two-part transmission fee). The level of the energy charge per kWh could be adjusted on a quarterly basis, according to the firm's performance. The total cost of salaries are related expenses in 2003, excluding any reward for good performance, is estimated to be 0.79 lp/kWh and ideally this cost should be recovered through the demand charge; only the "extra" revenue should be allocated to the energy charge. In a two-part fee the demand charges should be stable.

In theory the level of "Salaries and related expenses" could also be decreased by a certain percentage, based on poor performance. Reductions in transmission revenue could be imposed by reducing the level of the energy charge per kWh. The disadvantage of this approach, however, is that it could cause qualified staff to leave the company, causing the overall level of performance to become even worse.

In sum, the absence of a profit motive for HEP Transmission, coupled with the absence of "customer service" responsibilities and commercial quality indicators,[46] means that traditional Performance Based Ratemaking, as that term is customarily defined, does not apply in this context.[47] Instead, however, it appears that the incentive regulation could be

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[46] "Commercial quality concerns the quality of relationships between a supplier and a user." See R. Malaman et al., *Quality of Electricity Supply: Initial Benchmarking on Actual Levels, Standards, and Regulatory Strategies*, page 3. Prepared for the Council of European Energy Regulators, April 2001.

[47] "The fundamental principle behind PBR is that good utility performance should lead to higher profits, and poor performance should lead to lower profits." Bruce Biewald et al., *Performance-Based Regulation in a*

included by adjusting target level of "salaries and related expenses" and adjusting the energy charge as noted above.

If HEP Transmission contractually assumes certain operational functions, then additional indicators of good performance could be included in the evaluation that is used to adjust the target level of "salaries and related expenses" through adjustments in the energy component of the transmission fee. These indicators could include a few of the commercial quality standards for which data on Italy, the Netherlands, Portugal, Spain, and the United Kingdom are shown in the benchmarking report submitted to the Council of European Energy Regulators.[48] The following examples are similar to the commercial quality standards in Annex 2 of that report:

- *Estimating charges (complex cases).* Percentage of requests for new connections for which HEP Transmission provided an estimate of charges within 40 working days
- *Estimating charges (simple cases).* Percentage of simple requests for which HEP Transmission provided an estimate of charges within 20 working days
- *Notice of supply interruption.* Minimum of 24 hours before interruption
- *Queries on charges and payments.* Percentage of queries for which HEP Transmission gave a response within 15 working days
- *Response to customer claims.* Percentage of customer claims for which HEP Transmission gave a response within 15 working days

The next step in defining such performance targets is to (1) identify more specifically targets and salary impacts for the core functions we know HEP Transmission will perform; and (2) resolve the nature of the ISMO-HEP Transmission relationship in order to determine whether HEP Transmission will assume additional functions so that the target level of "salaries and related expenses" can be adjusted on the basis of additional, more traditional performance targets.

Restructured Electric Industry, page 8. Prepared for the National Association of Regulatory Utility Commissioners, November 8, 1997.

[48] *Quality of Electricity Supply: Initial Benchmarking on Actual Levels, Standards, and Regulatory Strategies*, Annex 2, Commercial Quality Standards.

Chapter 12 Long run marginal cost of transmission

In the May 2002 draft of the work plan for this tariff study there was a proposal to estimate the long run marginal cost of transmission for HEP Transmission. Although the working group decided that this task would not be accomplished within the time frame of the study, it is important to note that the cash flow forecast for years 2004 through 2007 is only a rough estimate and therefore we are unable to calculate the level of the transmission fee in 2004 and subsequent years. The calculation of LRMC could provide some valuable insights regarding the relationship of the transmission fee to the demand projection.

The LRMC of electric *generation* is an important concept for any company making investments in generating facilities, because generation is normally a competitive sector and high-cost generating units can become stranded assets when there is surplus generating capacity in the marketplace. The LRMC of *transmission* is usually less important, because transmission is a small portion of the total cost of electricity to the final consumer and because the transmission network is a natural monopoly and therefore it is difficult for transmission assets to become "stranded," even when there is surplus transfer capacity in the network. If it is expensive for a transmission company to meet load growth, the customer will have to pay for the cost of network improvements but the transmission company will not be threatened by competition.

An increase in load growth on the Croatian power system will require additional transmission capacity. The correct way to calculate LRMC is to develop a least-cost plan for investment in the transmission system under a "base case" load forecast, and then develop another least-cost plan for investment in the transmission system under a "base case plus 100 MW" load forecast or some other incremental forecast. The incremental load in MW must not be so small that it becomes insignificant and has no effect on the least cost plan, and it must not be so large that it totally changes the least cost plan (from a 220 kV network to 400 kV, for example). The net present value of capital expenditures should be calculated under both scenarios, and divided by the net present value of the incremental load in MW. The result is a cost per incremental MW. This is the "true cost" of load growth on the transmission system. It depends on precisely where the load growth occurs.

The fixed cost component of a transmission fee is usually based on average cost, not marginal cost. To some degree this "hides" the true cost of load growth. If transmission fees are below LRMC and if system load is projected to grow, the transmission fees will have to rise to LRMC someday. If transmission fees are above LRMC because these fees cover original equipment costs plus reconstruction and repair costs related to war damage, the transmission fees will gradually fall to LRMC as the asset base gradually returns to "normal." The LRMC of transmission is a useful number when it is necessary to make a long-term forecast of transmission system revenues - for example, to evaluate the transmission company's ability to repay long-term loans.

APPENDIX A

Previous Page Blank